PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

July 14, 2017

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

RE: UM ____—PacifiCorp's Draft Energy Storage Potential Evaluation

PacifiCorp d/b/a Pacific Power (PacifiCorp) submits for filing with the Public Utility Commission of Oregon (Commission) the company's Draft Energy Storage Potential Evaluation in compliance with Order No. 16-504. Confidential information in this filing is provided in accordance with OAR 860-001-0070.

This filing also includes a motion for a standard protective order in this matter.

PacifiCorp respectfully requests that all communications related to this filing be addressed to:

Oregon Dockets
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
oregondockets@pacificorp.com

Dustin Till
Senior Counsel
825 NE Multnomah Street, Suite 1800
Portland, OR 97232
Dustin.till@pacificorp.com

In addition, PacifiCorp respectfully requests that any informal information requests in this docket be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

Informal questions concerning this filing may be directed to Natasha Siores at (503) 813-6583.

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM ___

In the Matter of PACIFICORP d/b/a PACIFIC POWER's, Draft Energy Storage Potential Evaluation.	MOTION FOR GENERAL PROTECTIVE ORDER *Expedited Consideration Requested*

Under ORCP 36(C)(7) and OAR 860-001-0080(1), PacifiCorp d/b/a Pacific Power (PacifiCorp) moves the Public Utility Commission of Oregon (Commission) for entry of a general protective order in this proceeding. On July 14, 2017, PacifiCorp submitted its Draft Energy Storage Potential Evaluation that provides confidential business information as well as information from independent vendors seeking to demonstrate their experience to deploy energy storage projects or programs on the company's behalf. Good cause exists to issue a Protective Order to protect commercially sensitive and confidential business information related to PacifiCorp's Draft Energy Storage Potential Evaluation.

The Commission's rules authorize PacifiCorp to seek reasonable restrictions on discovery of trade secrets and other confidential business information.[1] The Commission's general protective order is designed to allow the broadest possible discovery consistent with the need to protect confidential information.[2] PacifiCorp anticipates participating in stakeholder workshops where proprietary cost data and models, commercially sensitive

[1] *See* OAR 860-001-0000(1) (adopting the ORCP); ORCP 36(C)(7) (providing protection against unrestricted discovery of "trade secrets or other confidential research, development, or commercial information"). *See also In re Investigation into the Cost of Providing Telecommunication Service,* Docket UM 351, Order No. 91-500 (1991) (recognizing that protective orders are a reasonable means to protect trade secrets and other confidential commercial information and "to facilitate the communication of information between litigants").
[2] OAR 860-001-0080(2).

pricing information, and confidential market analyses and customer-specific information will be discussed. PacifiCorp will be exposed to competitive injury if it is forced to make unrestricted disclosure of its confidential business information.

This matter is not a contested case that provides intervenors with discovery rights. Nonetheless, it is substantially likely that parties to this proceeding will make informal information requests of PacifiCorp that may implicate confidential and proprietary business information. Issuance of a protective order will facilitate the voluntary production of relevant information by PacifiCorp and expedite the informal information exchanges.

For these reasons, PacifiCorp respectfully requests that the Commission enter its general protective order in this docket. The company requests expedited consideration of this motion to allow stakeholders timely review of PacifiCorp's Draft Energy Storage Potential Evaluation.

Respectfully submitted this 14th day of July 2017.

By: ______________________

Dustin Till
Senior Counsel
PacifiCorp d/b/a Pacific Power

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

PacifiCorp Energy Storage
Draft Evaluation

July 2017

Table of Contents

PacifiCorp
Draft Energy Storage Potential
Evaluation

Introduction

PacifiCorp, d/b/a Pacific Power (PacifiCorp or the Company), respectfully submits this Draft Energy Storage Evaluation (Evaluation) to the Public Utility Commission of Oregon (Commission), to meet the requirements in Order No.16-504 (Order) for energy storage potential evaluation in Pacific Power's Oregon service territory. PacifiCorp will use the evaluation to help inform project proposals submitted by January 1, 2018.

Executive Summary

House Bill 2193 directs the electric companies in Oregon to submit proposals for qualifying energy storage systems with the capacity to store at least 5 MWh of energy. The proposals need to be supported by a comprehensive evaluation of the potential to store energy, including an analysis of operations and system data, examination of how storage could complement existing company action plans and identify areas with the opportunity to incentivize energy storage.

Pacific Power and parties in docket UM 1751 worked collaboratively to develop the specific requirements for the electric company draft evaluations that would later inform the final project proposals submitted no later than January 1, 2018. These requirements include analysis of use cases and applications, identifying applications for energy storage and the criteria used to determine their value, identification of locations with energy storage potential, methodology for establishing energy storage potential, estimated cost effectiveness of the addition of energy storage, assessment of benefits to the system and customer and providing material inputs, assumptions and other calculations.

On March 27, 2017, PacifiCorp issued a request for information (RFI) to potential suppliers of turnkey energy storage solutions and their respective technologies to find viable energy storage technologies and contractors who could demonstrate experience deploying or implementing cost-effective and reliable energy storage projects to meet the 2020 procurement guideline in House Bill 2193[1]. Prior to beginning the process to develop the final project proposals due no later than January 1, 2018, PacifiCorp will review the results of the draft evaluation to determine if any of the proposed RFI responses from potential vendors are compatible with the draft evaluation selected use cases. If any RFI responses are compatible, the Company intends to allow those vendors to participate in any future energy storage request for proposals that are directly related to this initiative. As required by UM 1751, when selecting a particular project the Company will include any pertinent findings from the RFI.

On February 17, 2017, PacifiCorp issued a request for proposals (RFP) seeking a qualified consultant to prepare a storage potential evaluation report and conduct an assessment of the Company's Oregon service territory. The purpose of the RFP was to: 1) have Bidders describe their proposed strategies and methodologies to prepare an evaluation of energy storage potential in Pacific Power's Oregon service territory that materially complies with docket UM 1751; 2)

[1] House Bill 2193, Section 2 (1)

solicit quotes for pricing for the potential evaluation; and 3) obtain references demonstrating Bidder's qualifications to perform the work proposed under this RFP. Bidders were encouraged to leverage existing information and data on energy storage from the Company's IRP; specifically, the Battery Energy Storage Study for the 2017 IRP.

Draft Evaluation Requirements

Through a competitive selection process, PacifiCorp obtained the services of DNV GL to develop methodologies that would assess a variety of use cases and execute these methodologies on selected sites to demonstrate their performance and develop initial results upon which further analysis could be conducted. The draft evaluation was conducted qualitatively on the transmission system, and quantitatively on the distribution system (6 feeders and 1 large customer site). The use cases evaluated included transmission congestion relief and deferral, frequency response, volt/VAR optimization, reliability, distribution asset deferral, distributed storage for distribution asset deferral, and stacked applications at a customer site for reliability, including renewables integration and micro-grid formation, frequency response, and distribution upgrade deferral. Definitions utilized in DNV GL's report are defined within the report or, in the case of abbreviations, consolidated at the beginning of the report. Assumptions and methods are provided in detail in the report to allow for transparent review by the Commission and all parties. Details on the cost estimates and market evaluations conducted are also explained in various sections of the report.

The Evaluation specifically meets the storage potential evaluation requirements 2a-2h of the Order by analyzing the following:[2]

> <u>Storage Potential by Use Case or Application for Specified Time Frames</u>
> Staff recommended the utilities study each use case for every application. However, it was recognized by all parties during the preceding workshops that not every use case would be applicable to all specific circuits and locations chosen in the evaluation, and the utilities would make note of such instances in the final draft evaluation. For example, the evaluation would not consider transmission services use cases for behind the meter applications. As such, electric utilities were encouraged to analyze each use case identified in Commission Staff's March 21, 2017 public meeting memo, as it applied to each application and location.
>
> Throughout the DNV GL report, use cases are selected (Section 2) and analyzed (Sections 4 through 6), with the results consolidated and discussed (Section 7). Sources and references are noted throughout the DNV GL report and cited in Sections 3 and 8.
>
> <u>Higher- and Lower-Value Applications</u>
> Applications selected for consideration include transmission-connected (frequency response and congestion relief), distribution-connected (volt/VAR optimization, reliability, distribution asset deferral), and customer-sited (reliability, stacked applications). See Sections 2.2 and 2.3 of the DNV GL report.

---

[2] *In the Matter of Public Utility Commission of Oregon Implementing Energy Storage Program Guidelines pursuant to House Bill 2193*. Docket No. UM 1751, Order No. 16-504 (Order No. 16-504) at 8 (Dec. 28, 2016). See Requirements 2a-2h.

Criteria for Designating Higher-and Lower-Value Applications and How the Criteria Were Applied.

Applications were selected as high vs low value through a multiphase process. The first step was a detailed review of the Battery Energy Storage Study for PacifiCorp's 2017 IRP, which assigned a score to various battery technologies for different use cases. A portion of this score was dependent on high-level cost effectiveness and regulatory analysis of the PacifiCorp territory, which was used to partially inform what applications would be most appropriate generally for PacifiCorp. In addition, the requirement of House Bill 2193 and the subsequent Order were considered, as these economics were not directly considered in the original ranking. Finally, known loading, voltage, or reliability issues on the PacifiCorp grid were taken into account in making the final selection, see Section 2.2.

Additionally, the use case's economic value to both the utility and the customer are not always comparable and may sometimes be in conflict, with the benefits of different use cases varying between each application making it hard to quantify. However, in the course of the analysis, a Benefit-Cost Ratio was calculated by DNV GL for each examined scenario to provide a single metric to compare value across multiple varied conditions (Section 1).

System Locations with the Greatest Storage Potential

PacifiCorp selected six (6) feeders and one (1) customer site with known needs matching those of the selected use cases, including voltage issues, transformers near overloading, and locations where reliability is a key concern. These feeders and site were assessed qualitatively and discussed to determine which use cases were appropriate for the local conditions. The quantitative assessment of these sites, and their appropriateness for various use cases are discussed in Section 4 through Section 6. Each assessment included descriptions of the inputs needed and used, descriptions of the methodology planned, limitations or assumptions of the methodology proposed, and results from the execution of the methodology, including storage size considered or optimized for, benefit to the system or the customer, calculation of economic comparative metric, and opportunities to stack benefits of multiple applications or to distribute storage over the grid at customer sites.

Methodology for Determining Storage Potential, How the Methodology Was Applied, and All Limiting Factors that Affect Estimates of Storage Potential by Application.

Each use case was assessed using different tools and methodologies, which are noted below in the table. In addition to the items below, a qualitative review was conducted of the congestion on the transmission system and a high level assessment was conducted of the whole system for the distribution upgrade deferral case. Each case also relied on various sources, cited in the body of the report and consolidated in Section 3 and Section 8, as well as additional supporting tools which, for example, produced model load curves where exact load profiles were not available. See Section 4 through Section 6 for details on how each methodology varied.

<table>
<tr><td></td><td>Transmission Connected</td><td colspan="4">Distribution Connected</td></tr>
<tr><td>Primary tool utilized</td><td>ES Grid</td><td>Syngergi</td><td>ES Grid</td><td>MGO</td></tr>
<tr><td rowspan="2">Use case</td><td rowspan="2">Frequency response</td><td>Voltage constraint</td><td rowspan="2">Distribution upgrade deferral</td><td rowspan="2">Customer sited bundled applications</td></tr>
<tr><td>Reliability</td></tr>
</table>

As previously noted, the methodologies result in the production of a storage size to be considered or optimized for, the benefit to the system or the customer, the calculation of economic comparative metric, and opportunities to stack benefits of multiple applications or to distribute storage over the grid at customer sites.

<u>Input, Assumptions, and Other Calculations Used to Designate Higher- and Lower-Value Applications and Locations with Greatest Potential.</u>
Inputs were provided from PacifiCorp, publicly available data, and/or industry experience. Assumptions generally included imprecision of data (either due to lack of availability or forecasts) and simplification of cases to allow for ease of modeling (such as even distribution risk of outage over the entire circuit or assumption of full loading of transformer prior to upgrade). See Section 4 through Section 6 for details of each use case's methodology inputs.

<u>Results of the Company's RFI</u>
The Company released the RFI which outlined the requirements of HB 2193 and UM 1751, and sought to identify:

1. Viable energy storage technologies that can be deployed rapidly, and with operational confidence; and
2. Engineer-procure-construct (EPC) contractors for viable energy storage (ES) technologies that have the ability to be installed by 2020.

The Company was particularly interested in energy storage technologies that supply location specific service that will improve system operation and reliability and have the ability to defer or eliminate the need for system upgrades. As a result, vendors were required to demonstrate experience deploying or implementing cost-effective, reliable and innovative energy storage projects or programs capable of offsetting and/or deferring the need to acquire traditional transmission and distribution (T&D) equipment, reduce generation, provide T&D system load relief and/or ancillary services.

The RFI closed to respondents on April 28, 2017. The Company receive nineteen (19) responses varying in services provided and resource type/approach. Below is a high level summary table of the RFI results:

Services	Design and Installation Contractor Engineering Services Installation Contractor Manufacturer Software
Resource Type/Approach	Aggregated Energy Storage Systems Lithium Ion Battery Fly Wheel Sodium Sulfur Battery Software Iron Flow Battery Custom Design Power to Gas Technology

Integrated Resource Plan (IRP)

Both House Bill 2193[3] and Order [4] call for an examination of how energy storage would complement the Company's existing action plans. The Company produces an IRP that identifies the least-cost, least-risk preferred portfolio of resources to meet the Company's load and resource requirements over a 20-year study period. Included in the IRP are forecasts of the expected retail customers and retail loads, alternative load forecast scenarios, and detailed production cost modeling that captures the impact of random fluctuations in loads. In addition, the Company conducts resource portfolio analysis based on different scenarios over the long-term planning horizon. The draft energy storage evaluation and project proposals evaluate specific energy storage projects with a focus on distribution-level and ancillary service applications that are distinct from the modeling considerations in the IRP. The energy storage projects identified in PacifiCorp's project proposals will serve the diverse and variable needs of its Oregon customers at a distribution level and are distinct and separate from the established long-term, integrated resource planning process of the IRP that focuses on the preferred mix of resources to serve bulk power system needs performed in the IRP. While the IRP is not the appropriate forum to evaluate specific energy storage project proposals like the proposals being developed for this docket, the Company has and will continue to work with stakeholders through the IRP public input process to develop energy storage sensitivities and analysis to be considered in the IRP planning cycle. In the 2017 IRP, for example, Pacific Power conducted two energy storage project sensitivities, and will continue to evaluate additional benefits of energy storage within the long-term planning process.

Methods used to estimate the value of energy storage systems are still under development that would inform project selection. Specifically, the value of a specific resource in isolation is quite

[3] House Bill 2193, Section 2 (b)(B)
[4] Order No. 16-504 at1-2

different from making portfolio decisions based on the relative value of different resources that lead to least-cost, least-risk outcomes for the Company's entire system, not just Oregon. The Company recommends that the Commission consider the unique system characteristics of each utility and continue to allow flexibility in how utilities evaluate energy storage resources in their IRP and procurement processes separate from the specific energy storage projects being considered in this docket.

Next Steps

While the draft energy storage evaluation demonstrates promise in deploying energy storage solutions within PacifiCorp's Oregon service territory, the potential projects analyzed require more detailed technical analysis, financial analysis, and vetting via PacifiCorp's normal capital approval process. The Company will develop project proposals through the normal capital approval process while leveraging this draft evaluation, RFI results, and stakeholder feedback. PacifiCorp looks forward to receiving feedback from Commission Staff and stakeholders on the Evaluation in an effort to inform the development of the Company's final project proposal submissions on or before January 1, 2018.

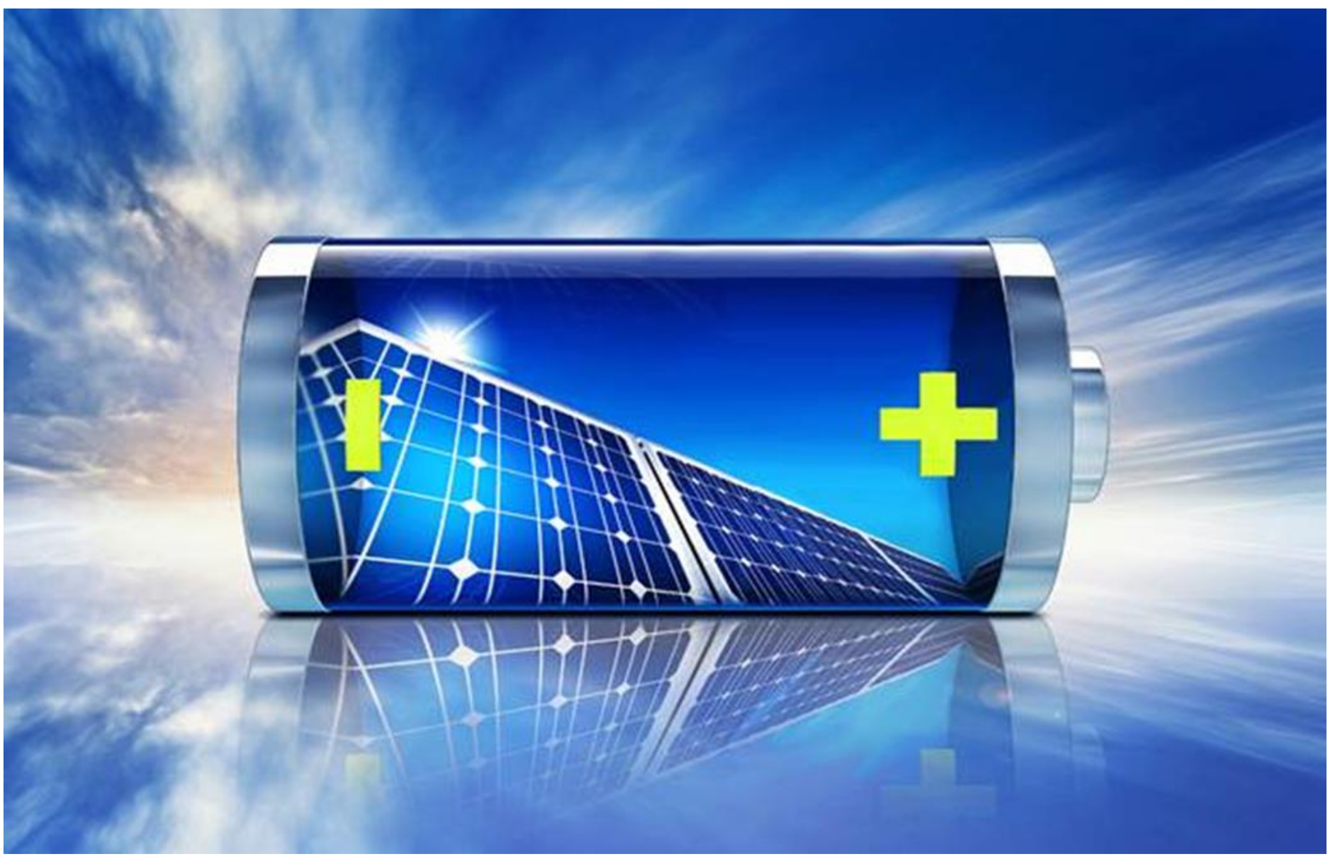
PACIFIC POWER
A DIVISION OF PACIFICORP

Attachment A – DNV GL Evaluation

Energy Storage Potential Evaluation

PacifiCorp

Report No.: 10046409-R-01-E
Issue: E Status: Final Draft
Date: 14 July 2017



IMPORTANT NOTICE AND DISCLAIMER

1. This document is intended for the sole use of the Customer as detailed on the front page of this document to whom the document is addressed and who has entered into a written agreement with the DNV GL entity issuing this document ("DNV GL"). To the extent permitted by law, neither DNV GL nor any group company (the "Group") assumes any responsibility whether in contract, tort including without limitation negligence, or otherwise howsoever, to third parties (being persons other than the Customer), and no company in the Group other than DNV GL shall be liable for any loss or damage whatsoever suffered by virtue of any act, omission or default (whether arising by negligence or otherwise) by DNV GL, the Group or any of its or their servants, subcontractors or agents. This document must be read in its entirety and is subject to any assumptions and qualifications expressed therein as well as in any other relevant communications in connection with it. This document may contain detailed technical data which is intended for use only by persons possessing requisite expertise in its subject matter.

2. This document is protected by copyright and may only be reproduced and circulated in accordance with the Document Classification and associated conditions stipulated or referred to in this document and/or in DNV GL's written agreement with the Customer. No part of this document may be disclosed in any public offering memorandum, prospectus or stock exchange listing, circular or announcement without the express and prior written consent of DNV GL. A Document Classification permitting the Customer to redistribute this document shall not thereby imply that DNV GL has any liability to any recipient other than the Customer.

3. This document has been produced from information relating to dates and periods referred to in this document. This document does not imply that any information is not subject to change. Except and to the extent that checking or verification of information or data is expressly agreed within the written scope of its services, DNV GL shall not be responsible in any way in connection with erroneous information or data provided to it by the Customer or any third party, or for the effects of any such erroneous information or data whether or not contained or referred to in this document.

4. Any energy forecasts estimates or predictions are subject to factors not all of which are within the scope of the probability and uncertainties contained or referred to in this document and nothing in this document guarantees any particular energy output.

KEY TO DOCUMENT CLASSIFICATION

Strictly Confidential	:	For disclosure only to named individuals within the Customer's organisation.
Private and Confidential	:	For disclosure only to individuals directly concerned with the subject matter of the document within the Customer's organisation.
Commercial in Confidence	:	Not to be disclosed outside the Customer's organisation.
DNV GL only	:	Not to be disclosed to non-DNV GL staff
Customer's Discretion	:	Distribution for information only at the discretion of the Customer (subject to the above Important Notice and Disclaimer and the terms of DNV GL's written agreement with the Customer).
Published	:	Available for information only to the general public (subject to the above Important Notice and Disclaimer).

Report title:	Energy Storage Evaluation	
Customer:	PacifiCorp	
	825 NE Multnomah St, 20th Floor	DNV GL - Energy
	Portland, OR 97232	Energy Advisory
Contact person:	Greg Stratton	4377 County Line Rd
Date of issue:	07/14/2017	Chalfont, PA 18914
Report No.:	10046409-R-01-E	Tel: +1 215 997 4500
Issue:	E	
Status:	Final	

Prepared by:	Verified by:	Approved by:
Victoria Carey	Michael Kleinberg	J. David Erickson
S.Lahiri, J.Flinn, N.Mirhosseini, W.Zhang, V. Carey	M. Kleinberg	J. David Erickson

☐ Strictly Confidential
☐ Private and Confidential
☐ Commercial in Confidence
☐ DNV GL only
☒ Customer's Discretion
☐ Published

Keywords:
Energy Storage, Use Case Assessment, Modeling

Issue	Date	Reason for Issue
A	6/20/2017	In-progress draft issue
B	6/30/2017	In-progress draft issue
C	7/6/2017	In-progress draft issue
D	7/8/2017	Final draft for client approval
E	7/11/2017	Final issue

Table of Contents

List of Tables

List of Figures

List of abbreviations

AC	Alternating Current
ACE	Area Control Error
AGC	Automatic Generation Control
BCR	Benefit/Cost Ratio
BESS	Battery Energy Storage System
BMS	Battery Management System
BPA	Bonneville Power Administration
C&I	Commercial and Industrial
CAISO	California Independent System Operator
CPCs	Control Performance Standards
DC	Direct Current
EIM	Energy Imbalance Market
EPC	Engineer Procure Construct
ESS	Energy Storage System
FR	Frequency Response
FRO	Frequency Response Obligation
HV	High Voltage
IRP	Integrated Resource Plan
IRR	Internal Rate of Return
ISO	Independent System Operator
Li-Ion	Lithium-Ion
LMP	Locational Marginal Price
LV	Low Voltage
MCC	Marginal Congestion Component
MEC	Market Energy Component
MLC	Marginal Loss Component
MV	Medium Voltage
NCM	Nickel Cadmium Manganese
NERC	North American Reliability Council
NPV	Net Present Value
O&M	Operations and Maintenance
OPUC	Public Utility Commission of Oregon
POI	Point of Interconnection
PV	Photovoltaic
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
UPS	Uninterruptible Power Supply
WECC	Western Electricity Coordinating Council

1 EXECUTIVE SUMMARY AND DOCUMENT SCOPE

PacifiCorp D/B/A Pacific Power (referred to in this document as "PacifiCorp" or "the Company") has developed this document and the process and results described herein to comply with Oregon's 2015 HB 2193, the subsequent Order 16-504 UM 1751, and the final guidelines from the Public Utility Commission of Oregon (OPUC) relating to these items. PacifiCorp's understanding of these requirements is described below:

1. Identify energy storage potential by use case or application with the ability to be implemented by year end 2026. The use of the 2026 time horizon is understood to limit uncertainty associated with the volatility of energy storage costs and technology. A key objective is to provide recommendations for storage projects and their proposed use that can be procured by 2020.
2. Identify higher- and lower-value applications for energy storage.
3. Develop criteria for designating higher- and lower-value applications and explain how the criteria are applied.
4. Identify locations within the Company's service territory in the state of Oregon with the greatest energy storage potential, including applications such as customer-side (e.g. residential, commercial, industrial) and/or utility-side (e.g. distribution and transmission).
5. Develop a recommended methodology for determining energy storage potential, including:
    - How the methodology should be applied, and
    - Identification of critical limiting factors that affect estimates of storage potential by application.
6. Provide all material inputs, assumptions, and other calculations needed to designate higher- and lower-value applications.
7. Estimate potential costs and associated cost effectiveness of the addition of energy storage to the Company's system.
8. Provide an assessment of potential qualitative and quantitative benefit of energy storage to the electric system and customer.

In this draft energy storage potential evaluation, PacifiCorp contracted and collaborated with DNV GL to develop methodologies to assess a variety of use cases for energy storage, execute these methodologies on selected to sites located within PacifiCorp's Oregon service territory to demonstrate their performance, and develop initial results upon which further analysis could be conducted to select the most appropriate case for future implementation. This draft evaluation was conducted qualitatively on the transmission system, and quantitatively on six feeders and one large customer site. The use cases evaluated were transmission congestion relief and deferral, frequency response, volt/VAR optimization, reliability, distribution asset deferral, and customer sited storage, including stacked applications at a customer site for reliability (including renewables integration and microgrid formation), frequency response, and distribution upgrade deferral. Additionally, the distribution asset deferral case was examined at a high-level for implications on the whole system.

Where possible, a benefit-cost ratio (BCR), which is defined as the value of benefits divided by the value of the costs, was used as the standard to compare the cases. The larger the value of the BCR, the more favorable the economics of the project. A BCR of 1 indicates a project in which the costs are equivalent to the benefits. Additional details about the economic considerations specific to each use case are described within the noted document references. Based on PacifiCorp's cost of traditional grid upgrades versus the cost of implementation of energy storage as well as the needs of the grid and customers, the most viable options from the results of these studies are summarized in Table 1-1. Other options are described in further detail within the noted sections. The transmission congestion relief and substation level reliability applications were not found to be necessary or effective under current grid conditions, and are thus not noted within this chart.

Table 1-1 Summary of most viable modeling results

Use Case	Energy Storage System Size	Economic considerations	Document reference
Frequency response	10 MW / 2 MWh (20 year FR contract @ $81/kW-yr)	BCR = 1.78	Section 4.1
Volt/VAR	17 kVA / 4 hr (Addresses 1 voltage violation, high cost capacitor upgrade)	BCR = 1.56	Section 5.1
Distribution upgrade deferral	(1) 1 MW / 2 MWh 2 years deferral Stand alone, and stacked with frequency response @ $81/kW-yr (2) 4 MW / 8 MWh 7 years deferral Stand alone, and stacked with frequency response @ $81/kW-yr	(1) Stand alone BCR = 0.36 Stacked BCR = 0.81 (2) Stand alone BCR = 0.27 Stacked BCR = 0.41	Section 5.3
Customer Sited with Stacked Applications	(1) 2 MW / 4 MWh ESS + PV, 4 years deferral, and frequency response @ $81/kW-yr (2) 4 MW / 6 MWh ESS + PV, 6 years deferral, and frequency response @ $81/kW-yr	(1) BCR = 1.36 (2) BCR = 1.35	Section 6.1

For these results, the systems were assumed to be generic Lithium Ion battery energy storage systems (BESS) of the noted size. Although other types of chemistries and technologies can and should be considered, this assumption reduced variables in the modeling and allowed for more direct comparison between cases. Other technologies are discussed in further detail in later sections of the report.

The challenge in comparing these varied use cases is in determining their economic value to both the utility and the customer, values which are not always comparable and may sometimes be in conflict. Additionally, economic value is not the only type of value PacifiCorp is assessing. The BCR scores therefore are not as nuanced as the full consideration of each potential project, but provide a single metric to compare cases as a starting point of that full consideration.

Of the applications noted in Table 1-1, the most economically viable were those in which the benefits from use cases were stacked, including distribution upgrade deferral, frequency response, and solar + storage integration for reliability. The benefits from the volt/VAR use case were also proposed as stackable, although a detailed analysis of this option was not conducted. Further, the urgency of these use cases should be considered, with the voltage violations and transformer overloads being the primary concerns to PacifiCorp providing safe and reliable service. In these cases, though the costs PacifiCorp ascribes to traditional solutions are lower than those of the energy storage systems (ESS) proposed, the viability of stacked benefits can provide more favorable economics, especially when considered as a distributed aggregated resource, where customer sites may also receive non-economic benefit. As such, if it is determined that the traditional solutions are more expensive than originally cited, the economics of each case would improve in favorability.

As such, to ensure safe, reliable, and low-cost power to its customers, as well as to meet the requirements laid out by the state of Oregon and the OPUC, PacifiCorp is considering the noted options.

2 USE CASE AND APPLICATION SELECTION

2.1 High level use case and application descriptions

As cited in the Battery Energy Storage Study for PacifiCorp's 2017 Integrated Resource Plan (IRP) [1], energy storage systems can support multiple applications, with some more economically feasible or appropriate for Pacific Power's grid. Descriptions of the applications considered within that document are transcribed below.

> DNV GL reviewed applications for energy storage systems based on the regulations and standards in place in PacifiCorp territories, including the availability of financial resources to support energy storage development. Descriptions of these applications are provided below, based on the Department of Energy's Electricity Storage Handbook [2] in collaboration with NRECA and DNV GL's recommended practice guide, GRIDSTOR [3].

- Electric energy time shift – Energy storage systems operating within an electrical energy time-shift application are charged with inexpensive electrical energy and discharged when prices for electricity are high. On a shorter timescale, energy storage systems can provide a similar time-shift duty by storing excess energy production from, for example, renewable energy sources with a variable energy production, as this might otherwise be curtailed. If the difference in energy prices is the main driver and energy is stored to compensate for (for example) diurnal energy consumption patterns, this application is often referred to as arbitrage.

  Storing energy (i.e. in charge mode) at moments of peak power to prevent curtailment or overload is a form of peak shaving. Peak shaving can be applied for peak generation and also – in discharge mode – for peak demand (e.g. in cases of imminent overload). Peak shaving implicates that the energy charged or discharged is discharged or recharged, respectively, at a later stage. Therefore, peak shaving is a form of the energy time-shift application.

  An energy storage system used for energy time-shift could be located at or near the energy generation site or in other parts of the grid, including at or near loads. When the energy storage system used for time-shift is located at or near loads, the low-value charging power is transmitted during off-peak times.

  Important for an energy storage system operating in this application are the variable operating costs (non-energy related), the storage round-trip efficiency and the storage performance decline as it is being used (i.e. ageing effects).

- Electric Supply Capacity - An energy storage system could be used to defer or reduce the need to buy new central station generation capacity and/or purchase capacity in the wholesale electricity market. In this application, the energy storage system supplies part of the peak capacity when the demand is high, thus relieving the generator by limiting the required capacity peak. Following a (partial) discharge, the energy storage system is recharged when the demand is lower. The power supply capacity application is a form of generation peak shaving, therefore a form of electrical energy time-shift. An energy storage system participating in the electrical capacity market may be subject to restrictions/requirements of this market, for example required availability during some periods.

- Regulation - Regulation is used to reconcile momentary differences between demand and generation inside a control area or momentary deviations in interchange flows between control areas, caused by fluctuations in generation and loads. In other words, this is a power balancing application. Conventional power plants are often less suited for this application, where rapid changes in power output could incur significant wear and tear. Energy storage systems with a rapid-response characteristic are suitable for operation in a regulation application.

  Energy storage used in regulation applications should have access to and be able to respond to the area control error (ACE) signal (where applicable), which may require a response time of fewer than five seconds. Furthermore, energy storage used in regulation applications should be reliable with a high quality, stable (power) output characteristics.

- Spinning, Non-spinning, and supplemental reserves - A certain reserve capacity is usually available when operating an electrical power system. This reserve capacity can be called upon in case some generation capacity becomes unavailable unexpectedly, thus ensuring system operation and availability. A subdivision can be made based on how quickly a reserve capacity is available:

  - Spinning reserve is reserve capacity connected and synchronized with the grid and can respond to compensate for generation or transmission outages. In remote grids spinning reserve is mainly present to cover for volatile consumption. In case a reserve is used to maintain system frequency, the reserve should be able to respond quickly. Spinning reserves are the first type of backup that is used when a power shortage occurs.

  - Non-spinning reserve is connected but not synchronized with the grid and usually available within 10 minutes. Examples are offline generation capacity or a block of interruptible loads.

  - Supplemental reserve is available within one hour and is usually a backup for spinning and non-spinning reserves. Supplemental reserves are used after all spinning reserves are online.

    Stored energy reserves are usually charged energy backups that have to be available for discharge when required to ensure grid stability. An example of a spinning reserve is an uninterruptible power supply (UPS) system, which can provide nearly instantaneous power in the event of a power interruption or a protection from a sudden power surge. Large UPS systems can sometimes maintain a whole local grid in case of a power outage; this application is called island operation.

- Voltage support - Grid operators are required to maintain the grid voltage within specified limits. This usually requires management of reactive power (but also active power, e.g. in the LV grid), therefore also referred to as Volt/VAR support. Voltage support is especially valuable during peak load hours when distribution lines and transformers are the most stressed. An application of an energy storage system could be to serve as a source or sink of the reactive power. These energy storage systems could be placed strategically at central or distributed locations.

Voltage support typically is a local issue at low voltage (LV), medium voltage (MV) or high voltage (HV) level. The distributed placement of energy storage systems allows for voltage support near large loads within the grid. Voltage support can also be provided by operation of generators, loads, and other devices. A possible advantage of energy storage systems over these other systems is that energy storage systems are available to the grid even when not generating or demanding power.

Note that no (or low) real power is required from an energy storage system operating within a voltage/VAR support application, so cycles per year are not applicable for this application and storage system size is indicated in MVAR rather than MW. The converter needs to be capable of operating at a non-unity power factor in order to source or sink reactive power. The nominal duration needed for voltage support is estimated to be 30 minutes, which allows the grid time to stabilize and/or begin orderly load shedding.

- Load following / ramping support for renewables - Load following is one of the ancillary services required to operate a stable electricity grid. Energy storage systems used in load following applications are used to supply (discharge) or absorb (charge) power to compensate for load variations. Therefore, this is a power balancing application. In general, the load variations should stay within certain limits for the rate of change, or ramp rate. Therefore, this application is a form of ramp rate control. The same holds for generation variations, which is very applicable to renewable energy sources. Due to the intermittency of renewables production, having a storage device with several hour durations can provide a large advantage to renewable efficiencies, easing of grid impacts, and renewable production. Conventional power generation can also operate with a load following (or RES compensating) application. Within these applications, the benefits of energy storage systems over conventional power generation are that:

  - most systems can operate at partial load with relatively modest performance penalties
  - most systems can respond quickly with respect to a varying load
  - systems are suitable for both load following down (as the load decreases) and load following up (as the load increases) by either charging or discharging.

  Note that an energy storage system operating with a load-following or ramp rate control application within a market area needs to purchase (when charging) or sell (when discharging) energy at the going wholesale price. As such the energy storage efficiency is important when determining the value of the load following application.

- Frequency response - Synthetic inertia behavior is the increase or decrease in power output proportional to the change of grid frequency; physical inertia is provided by conventional power generators, i.e. synchronous generators. If the total amount of physical inertia decreases in a power system, the amount of synthetic inertia should be increased to maintain a certain minimum amount of total inertia. Many grid-connected renewable energy sources do not provide additional synthetic inertia. Therefore, larger grid frequency deviations may occur as the total inertia in the power system decreases. Keeping track of the total system inertia could be a future task of ISOs.

Some energy storage systems add synthetic inertia to the system and can thereby be used to compensate for fluctuations in the grid frequency. Causes of fluctuations could be the loss of a generation unit or a transmission line (causing a sudden power imbalance). Various generator response actions are needed to counteract a sudden frequency deviation, often within seconds.

Energy storage within a frequency response application could support the grid operator and thereby assure a smoother transition from an upset period to normal operation. For a frequency response type of application, the energy storage is required to provide support within milliseconds. Storage helps to maintain the grid frequency and to comply with Control Performance Standards (CPSs) 1 and 2 of the North American Reliability Council (NERC). Aside from this quick response, the frequency response application is similar to load following and regulation, as described previously.

- Transmission and distribution congestion relief – During moments of peak demand, it may occur that the available transmission lines do not provide enough capacity to deliver the least-cost energy to some or all of the connected loads. This transmission congestion may increase the energy cost.

  Energy storage systems at strategic positions within the electricity grid help to avoid congestion-related costs and charges. The energy storage system can be charged when there is no congestion and discharged when congestion occurs. Energy storage can, in this way, additionally delay and sometimes avoid the need to upgrade a transmission or distribution system.

DNV GL also, beyond what is noted from the IRP, considered the following application:

- Distribution upgrade deferral – Strategically placed electrical energy storage used within a distribution system may act as an energy buffer and alternative to major component replacements, thereby deferring distribution grid upgrades. The key consideration of energy storage in this application is that the system can provide enough incremental capacity to defer a large lump sum investment in new distribution equipment. As such the ESS is designed to serve sufficient load, as long as required, to keep the loading of the distribution equipment below a specified maximum to extend equipment service life. Another potential benefit of energy storage systems in this application is the minimization of the risk that a planned load growth does not occur after upgrades of transmission/distribution lines and transformers.

2.2 Criteria to determine application value

In the Battery Energy Storage Study for PacifiCorp's 2017 IRP [1], an application assessment methodology is laid out to assess the appropriateness of various energy storage technologies for PacifiCorp's territories. Although not specific exclusively to PacifiCorp's territory in Oregon, this assessment methodology provided the baseline for the use case value determination. Because this proposal is intended to be technology agnostic, the assessment here was only based on the PacifiCorp Application Need score. The score varies from 1 – 10, with 10 defining the technology that is best suited for the application. The section describing this is excerpted below, referencing the tables that follow:

> A PacifiCorp Application Need score was then assigned to each application based on the high-level cost-effectiveness and regulatory analysis of the PacifiCorp territory. Based on current PacifiCorp market scenario, storage applications with high value that are not dependent on market-related rule changes, such as T&D congestion relief, are expected to be the most likely candidates for PacifiCorp to deploy energy storage. Additionally, as noted in the review, renewable portfolio standards across the PacifiCorp service territory will drive some renewable integration applications such as renewable time shifting, regulation, and load following. Faster regulation applications such frequency response and voltage support are likely to be lower value applications. (Figure 2-1) A second set of Scores for PacifiCorp Application Need scores were provided for the alternative market scenario with PacifiCorp operating under market rules similar to those implemented in California ISO (CAISO). For this scenario, CAISO market rules which directly allow storage to qualify for supply capacity credit increased this application score. Also, further developed fast regulation and emerging ramping market products increased the PacifiCorp Application Need score for frequency regulation and applications tied to renewable integration. (Figure 2-2)

Application	Current Market Scenario						
	Li-Ion NCM	Li-Ion LiFePO4	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air
Electric Energy Time Shift	9	8	8	9	8	8	7
Electric Supply Capacity	9	9	9	9	8	8	7
Regulation	9	9	9	9	8	8	7
Spinning, Non-spin, Supplemental reserves	8	8	9	8	8	8	7
Voltage support	7	8	8	7	6	6	6
Load following / ramping support for renewables	8	8	9	8	8	8	7
Frequency response	7	7	8	7	6	6	5
Transmission and distribution congestion relief	9	9	9	9	9	9	8

Figure 2-1 Application ranking for current market scenario from Battery Energy Storage Study

Application	CAISO Market Scenario						
	Li-Ion NCM	Li-Ion LiFePO4	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air
Electric Energy Time Shift	9	9	9	9	9	9	7
Electric Supply Capacity	9	9	9	9	9	9	8
Regulation	9	9	9	9	8	8	7
Spinning, Non-spin, Supplemental reserves	9	9	9	9	8	8	7
Voltage support	7	8	8	7	6	6	6
Load following / ramping support for renewables	9	9	9	9	8	8	7
Frequency response	7	7	8	7	6	6	5
Transmission and distribution congestion relief	9	9	9	9	9	9	8

Figure 2-2 Application rankings for CAISO Market Scenario from Battery Energy Storage Study

The above rankings were tailored to particular BESS chemistries, rather than other non-chemical types of ESS, and were generalized for the full PacifiCorp territory, including locations outside of Oregon. However, the factors considered do not vary significantly between states, and as such, are representative of the predicted applicability of storage within Oregon only. The applications with values closest to 10 were thus assumed to be best suited for PacifiCorp in Oregon.

Additionally, the requirements and funding restrictions of 2015 HB 2193 and the subsequent Order 16-504 UM 1751 were considered, as these economics were not directly considered in the original ranking. As such, use cases appropriate to centralized or aggregated systems between 5 MWh and 25 MW, over a 10-year time frame, and with a focus on systems that "defer or eliminate the need for system upgrades, provide voltage control or other ancillary service, or supply some other location-specific service that will improve system operation and reliability" were given priority. Finally, PacifiCorp selected a variety of feeders and sites, and the known loading, voltage, or reliability concerns at such sites were taken into account in selecting the applications to be modeled.

2.3 Applications selected

Based on the criteria described in Section 2.2, the following use cases were selected for review:

- Transmission-connected
  - Frequency response
  - High level review of curtailment and congestion
- Distribution-connected

- Volt/VAR optimization
- Reliability
- Distribution asset deferral

- Customer sited
    - Customer reliability
        - Renewables integration
        - Microgrid formation
    - Frequency response
    - Distribution asset deferral
    - Stacked applications

3 ENERGY STORAGE COST ASSUMPTIONS

The Battery Energy Storage Study for PacifiCorp's 2017 IRP [1] (the Study) conducted by DNV GL was used to support cost assumptions for this report. Results presented in the Study were assumed mid-2016 storage costs. Storage costs are evolving rapidly and DNV GL has observed costs for NCM Li-Ion (the technology assumed throughout this report) trending to the low-end of the cost ranges presented in the Study. The values from the Study were updated based on current observed costs, with 2018 and 2021 values obtained by applying year-on-year cost reduction projection rates for each component noted. These assumptions are detailed in Table 3-1 and referenced throughout the report.

Table 3-1: Energy Storage Cost Assumptions

Cost Category	2018 Value	2021 Value
Energy storage equipment cost ($/kWh)	$234.81	$143.81
Power conversion equipment cost ($/kW)	$325.92	$303.62
Power control system cost ($/kW)	$78.40	$76.00
Balance of system ($/kW)	$66.67	$55.11
Installation ($/kWh)	$120.00	$120.00
Total Cost of power components ($/kW)	$470.99	$434.73
Total Cost of energy components ($/kWh)	$354.81	$263.81
Fixed O&M cost ($/kW yr)	$6.00	$6.00
Capacity maintenance cost ($/kWh-year)	$7.5	$7.5

The aggregated cost of energy components and power components will be used to calculate ESS project capital cost. For example, the total cost of a 2 MW 4 MWh system deployed in 2018 will be calculated as:

- Cost of power components is 2000 x $470, i.e. $940,000
- Cost of energy components is 4000 x 355, i.e. $1,420,000
- Total cost of ESS project at $2,360,000 is the sum of cost of power components and cost of energy components.

Details of the cost components are as follows:

- Energy storage equipment includes full DC battery system which includes the cost of energy storage medium, such as Li-Ion battery cells or flow battery electrolyte, internal wiring and connections, packaging and containers, and battery management system (BMS).
- Power conversion system equipment includes the inverter, packaging, container and inverter controls.

- Control system includes supervisory control software, along with the controller and communications hardware required to dispatch and operate ESS.
- Balance of system includes site wiring, interconnecting transformer, and additional ancillary equipment.
- Installation includes Engineer-Procure-Construct (EPC) costs inclusive of installation parts and labor, permitting, site design, procurement and transportation of equipment.
- Fixed operations and maintenance (O&M) costs are provided as real levelized dollars with assumed 20 year project life.
- Capacity maintenance cost is required to maintain the energy capacity of the system under degradation over project life. Capacity cost over a 20 year project is calculated by levelizing the cost of replacing the full DC battery system once at a replacement cost of $150/kWh.

4 TRANSMISSION-CONNECTED ENERGY STORAGE SYSTEM ASSESSMENT

These use-cases describe the methodology for evaluating the cost-effectiveness of ESS connected to the transmission system. Such systems are generally large, on the scale of several tens of Megawatts, and perform a single application. In de-regulated energy markets, such as PJM, participation in the frequency regulation market is the highest volume application for transmission-connected ESS. In a vertically integrated environment, frequency balancing resources may be procured through a bi-lateral contract with an asset providing Primary Frequency Response or Automatic Generation Control (AGC). The congestion on the transmission system was also considered qualitatively.

4.1 Frequency response system assessment

4.1.1 Inputs required

The inputs required for this use case evaluation are:

- Line frequency measurements at 1s time intervals for average summer, extreme summer, average winter, extreme winter, large event, and average event days
- Capital and operating costs of energy storage system
- Line frequency data for 20 frequency events in 2016 and 5 frequency events in 2017

4.1.2 Methodology description

In this application, the BESS monitors the line frequency and responds in accordance with a preset dispatch directive when the deviation in system frequency exceeds a certain threshold. This response time of frequency response in seconds is faster than the response time of a frequency regulation signal generated by an Independent System Operator (ISO). An ISO's frequency regulation signal is an integral function of the Area Control Error (ACE) of the balancing area, that is characterized by deviations of the line frequency from a nominal frequency.

In compliance with NERC Standard BAL-003-1 – Frequency Response and Frequency Bias Setting, PacifiCorp East has to maintain a Frequency Response Obligation (FRO) of -48.9 MW/0.1 Hz, while the FRO for PacifiCorp West is -19.5 MW/0.1 Hz [4]. This obligation implies that PacifiCorp is required to respond to a Western Electricity Coordinating Council (WECC)-wide frequency event with generation capacity in proportion to the magnitude of frequency deviation. For example, a frequency reduction by 0.2 Hz to 59.8 Hz would require an increase in generation of 39.0 MW by PacifiCorp West.

This evaluation methodology takes a bottom up approach by simulating storage system operations under typical frequency response events. Operational simulations are used to assess system energy capacity and performance requirements. Performance requirements include annual energy throughput, annual energy charging and annual number of cycles. Energy capacity requirement is used to size the ESS. The other performance requirements are used to estimate operating cost in terms of cost of charging energy and cost of capacity maintenance contracts.

The basic operating principle is as follows: the storage system will constantly monitor the grid frequency on the storage system side of the Point of Interconnection (POI) and continuously compute the rate of frequency change. If the frequency drops below a specified trigger point or if the frequency falls at a faster than specified rate, the ESS will respond with full assigned power capacity for a specified duration. If the state of charge of the ESS is below full capacity, the system will charge if the line frequency and the rate of change of line frequency are above a specified threshold. Ramping rates during charging are maintained within specified limits.

DNV GL analyzed frequency data for 20 frequency events in 2016 and 5 frequency events in 2017. Based on frequency data and industry standard examples, the operating parameters for a characteristic ESS providing 10 MW of frequency response capacity are provided in Table 4-1.

Table 4-1: Energy storage system operational parameters for frequency response use case

Parameter	Value
Real Power Output on frequency response trigger	10 MW discharging (under-frequency)
Duration of real power output on frequency response trigger	360s
Frequency threshold for frequency response trigger	59.927 Hz
Rate of change of frequency threshold for frequency response trigger	0.006% (based on 15s moving average)
Time between frequency event trigger and full power response from ESS	10s
After the conclusion of response duration, duration of response power ramp to zero power	360s
Ramp down time to zero power while discharging	120s
Frequency threshold to allow storage charging	Greater than 59.98 Hz
Rate of change of frequency threshold to allow charging	0.002% (based on 15s moving average)
Maximum down-ramp during charging cycle	1 MW/min
Maximum up ramp during charging cycle	1 MW/min

Figure 4-1 shows a simulation example of BESS responding to a frequency event. The response is triggered by line frequency dropping to 59.89 Hz. The BESS reaches full power output within 10s and sustains it for 6 minutes after which it ramps down to zero power within 120s. The BESS waits 12 minutes for system frequency to stabilize before initiating charging. Ramp rates during charging are within limits of 10% per minute, i.e. 1 MW per minute.

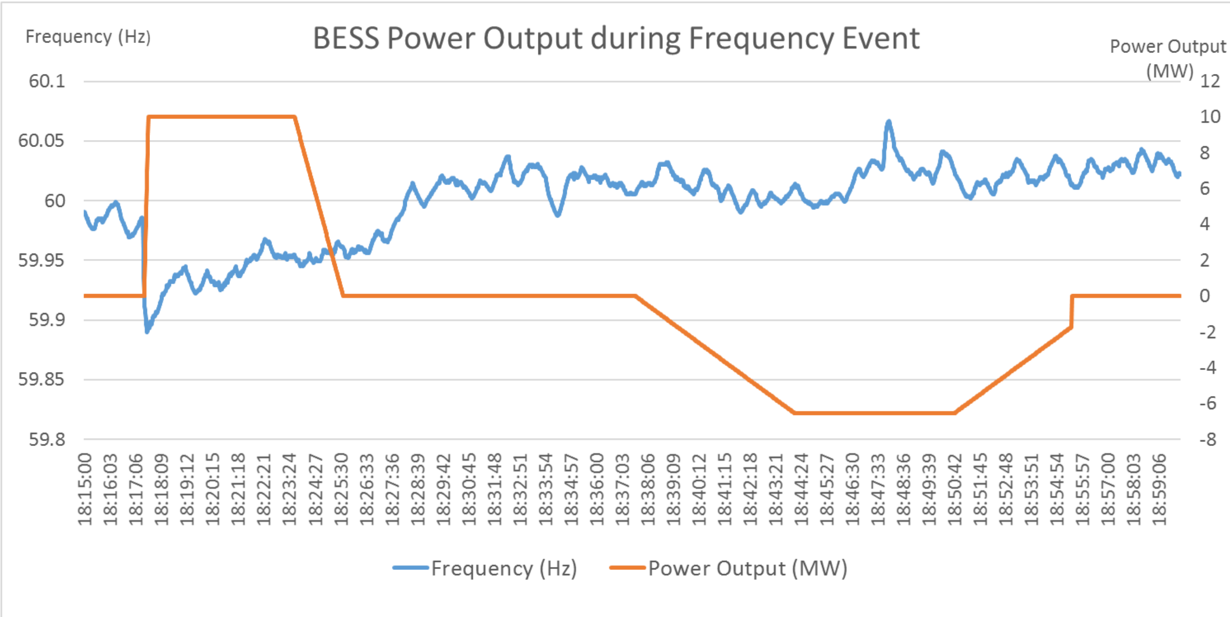


Figure 4-1: Simulation example of energy storage system to frequency response event

As shown in Figure 4-2, the state of charge of the battery system drops to 0.9 MWh from 2.2 MWh. The charging cycle lasts approximately 18 minutes until full state of charge is regained.

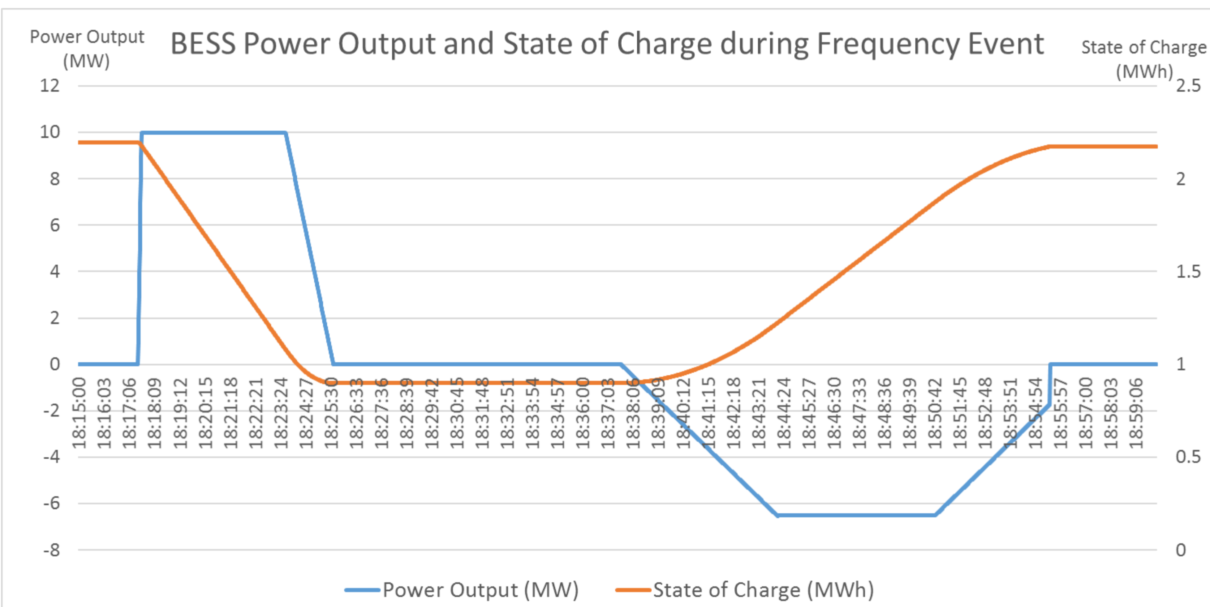


Figure 4-2: BESS power output and state of charge during frequency response event

4.1.3 Assumptions and methodology limitations

The cost-effectiveness analysis for ESS providing frequency response has been performed under the following assumptions:

- The value of frequency management services in a deregulated environment is determined by market requirement. In contrast, the contract value of frequency response service under a vertically integrated utility environment is determined through bilateral contracts and is not publicly available. This evaluation has referenced frequency response payment that a market operator CAISO, has contracted with two utilities in the Pacific Northwest. These contract values are assumed to be a proxy for the value of frequency response service to PacifiCorp.

- Primary frequency response balances instantaneous deviations between generation and load. Deviations may be caused by large scale renewable intermittency or contingencies such as generation trip and loss of transmission line. As the penetration of intermittent renewable resources increase, the power system is expected to require more frequency response. Fast response energy storage resources are ideally suited to perform frequency response. However, as with any resource or service, at sufficiently high volume of ESS deployment, the marginal value of additional deployment may decrease, i.e. the service may be saturated. We believe that the mandated volume of ESS deployment in Washington State will not result in a saturation of the frequency response service.

  Conditions in the mid-Atlantic ISO PJM may illustrate this point. Among ISOs, PJM has the highest volume of fast response ESS deployed to perform fast regulation (Reg D). Although Reg D response requirement is slower than primary frequency response, batteries and fly-wheels have the highest performance scores in the Reg D market [5]. Recent changes in the PJM market that went into effect on January 9, 2017 may reduce the revenue potential of batteries performing Reg D in PJM. This has led to speculation that the Reg D market in PJM is close to saturation due to high ESS deployment.

  However, under closer examination it is not clear whether the PJM Reg D market is close to saturation. The changes reflect a recalibration in commitment and dispatch methodology for Reg D resources. Selection of better performing resources such as batteries and fly-wheels is prioritized to reduce issues caused by market mechanics and operation of lower performance resources [6]. As of 2015, PJM Reg D market had approximately 700 MW of registered resources. However, 420 MW was hydro and only 140 MW was batteries and fly-wheels.

4.1.4 Modeling results

For this application, a battery system with a duration between 8 minutes and 15 minutes is sufficient. To evaluate the cost-effectiveness of a characteristic system, a battery system with 12-minute duration is considered. It is assumed that the storage system is procured through a 10-year contract. An estimated contract value provides the potential benefit for the cash-flow evaluation. The CAISO contract values are used as the representative value of frequency response contracts:

- CAISO contract with Bonneville Power Administration (BPA) for 50 MW/0.1 Hz of frequency response for $2.22 M per year or $44.40 per kW-year [7].

- CAISO contract with Seattle City Light for 15 MW/0.1 Hz of frequency response at $1.22 M per year or $81 per kW-year [8].

The contract value of $44.4 per kW-year provides a low-benefit estimate, whereas the contract value of $81 per kW-year may be considered as the high-benefit estimate.

The financial parameters and cost inputs to the cash flow model are based on typical industry values for Li-Ion Nickel Cadmium Manganese (NCM) battery systems as listed in Section 3, which were simplified to be applied to both high energy and high power batteries. For ESS installation in 2018, the cost of power components is assumed to be $471/kW and for energy components is assumed to be $355/kWh. The total cost of a 10 MW 12 minute ESS is calculated at $5,420,000, a value, as noted previously, based on projections from the Battery Energy Storage Study, which is in line with other similarly sized systems utilized for the same application observed in the PJM market. DNV GL believes that these costs are conservative and reasonable. A 20-year cash-flow analysis was performed using financial parameters supplied by PacifiCorp. These parameters were: debt to equity ratio, debt financing rate and financing period. Net Present Value (NPV) was calculated based on a discount rate of 6.59%. Financial results for a utility owned storage project in terms of the NPV, Internal Rate of Return (IRR), and BCR is shown in Table 4-2.

Table 4-2: Financial results under low and high benefit estimates for frequency response application

System description	NPV	IRR	BCR
10 MW, 2 MWh ESS with 20-year frequency response contract at $44.4 / kW-year	-$165,112	6.1%	0.97
10 MW, 2 MWh ESS with 20-year frequency response contract at $45.6 / kW-year	$4,626	6.6%	1.00
10 MW, 2 MWh ESS with 20-year frequency response contract at $81 / kW-year	5,011,896	22.2%	1.78

At a contract value of $44.40 / kW-year, the IRR is 6.1% and the storage project is marginally under cost-effectiveness. At the contract value of $81 / kW-year, the financial performance is very high with an IRR of 22.2%. The contract value of $45.6 / kW-year can be seen as the break-even point for cost-effectiveness.

Table 4-3 shows the 20-year cash-flow analysis for a 10 MW 2 MWh ESS performing primary frequency response at a contract value of $81 / kW-year. The revenue from primary frequency response is assumed to escalate at 2.5% per year. Debt payment term is 10 years.

Table 4-3: 20-year cash flow for 10 MW / 2 MWh energy storage system performing primary frequency response at contract value of $81/kW-**year ('000s)**

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Project revenue	$810.0	$830.3	$851.0	$872.3	$894.1	$916.4	$939.4	$962.8	$986.9	$1,011.6
Fixed O&M cost	($60.0)	($61.5)	($63.0)	($64.6)	($66.2)	($67.9)	($69.6)	($71.3)	($73.1)	($74.9)
Capacity maintenance cost	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)
Equity draw	($2,788.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Interest payment	($138.4)	($127.6)	($116.1)	($104.1)	($91.4)	($78.0)	($64.0)	($49.2)	($33.6)	($17.2)
Principal payment	($206.7)	($217.6)	($229.0)	($241.1)	($253.8)	($267.1)	($281.2)	($296.0)	($311.5)	($327.9)
Debt payment	($345.2)	($345.2)	($345.2)	($345.2)	($345.2)	($345.2)	($345.2)	($345.2)	($345.2)	($345.2)
Total revenue	$810.0	$830.3	$851.0	$872.3	$894.1	$916.4	$939.4	$962.8	$986.9	$1,011.6
Total cost	($3,208.2)	($421.7)	($423.2)	($424.8)	($426.4)	($428.1)	($429.7)	($431.5)	($433.3)	($435.1)
Annual cash flow	($2,398.2)	$408.6	$427.8	$447.5	$467.7	$488.4	$509.6	$531.3	$553.6	$576.5

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Project revenue	$1,036.9	$1,062.8	$1,089.4	$1,116.6	$1,144.5	$1,173.1	$1,202.4	$1,232.5	$1,263.3	$1,294.9
Fixed O&M cost	($76.8)	($78.7)	($80.7)	($82.7)	($84.8)	($86.9)	($89.1)	($91.3)	($93.6)	($95.9)
Capacity maintenance cost	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)	($15.0)
Equity draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Interest payment	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Principal payment	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Debt payment	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total revenue	$1,036.9	$1,062.8	$1,089.4	$1,116.6	$1,144.5	$1,173.1	$1,202.4	$1,232.5	$1,263.3	$1,294.9
Total cost	($91.8)	($93.7)	($95.7)	($97.7)	($99.8)	($101.9)	($104.1)	($106.3)	($108.6)	($110.9)
Annual cash flow	$945.1	$969.1	$993.7	$1,018.9	$1,044.7	$1,071.2	$1,098.4	$1,126.2	$1,154.7	$1,184.0

4.2 Qualitative Curtailment and Congestion Transmission Assessment

4.2.1 Methodology description

DNV GL has significant experience in performing detailed curtailment/congestion studies and utilizes industry best practices in establishing study design and assumptions. This section provides a brief overview of key elements and methods employed to assess curtailment at the Project, including DNV GL's approach to congestion and curtailment analysis.

DNV GL assesses congestion and curtailment risk through measuring the impact of individual transmission constraints that pose a congestion risk to the Project. Typically, a congestion analysis is conducted within a five-year window of the current date in order to utilize transmission planning and generation queue data maintained and provided by system operators. Such planning data generally does not extend beyond a five-year period. Congestion results may be sensitive to near-term market changes such as new generation entering service near the Project, transmission system upgrades, adjustments in market rules or structures, etc. Significant near-term expansion of wind and solar projects in the study area may constitute an important risk factor that can be investigated through analysis of future operations within the five-year planning window.

DNV GL understands that there are no third-party curtailment studies or transmission assessment studies available for this Project. Therefore, DNV GL performed a high-level, qualitative assessment of the curtailment risk and transmission assessment for the Project based on available information regarding the Project’s location, existing transmission planning documents from PacifiCorp, feasibility studies and system impact studies for nearby generation queues. For this review, DNV GL has also relied upon the CAISO and Energy Imbalance Market (EIM) published locational marginal price data (LMP) [9], and internal knowledge of the Pacific Northwest market.

4.2.2 Transmission System

PacifiCorp is considering several potential locations for the Project. The DNV GL high-level assessment focused on the following areas within the PacifiCorp service territory:

- Klamath Basin
- Willamette Valley
- Central Oregon

4.2.3 Location Marginal Prices

The LMP reflects the marginal cost of energy at each transmission node based on transmission congestion and losses on the system. The LMP is the sum of three components: the Market Energy Component (MEC), the Marginal Congestion Component (MCC), and the Marginal Loss Component (MLC). The MEC is the market clearing price for the marginal MW of load; MCC is the marginal cost of congestion at a given pricing point; the MLC is the marginal cost of losses at a given pricing point.

Historical prices at the selected representative points are an indicator of curtailment risk and transmission congestion, with negative prices indicating congestion and/or curtailment. Figure 4-1 lists historical LMP at

Proxy nodes in three areas of interest and the CAISO EIM Mid-C Scheduling Point (Mid-C SP). The average MCC was $-1.04/MWh in the Klamath Falls area, $-1.05/MWh in the Willamette Valley and Central Oregon areas, and $-0.76/MWh at the Mid-C SP in 2015. In 2016, the average MCC of these three areas are all decreased to $-0.40/MWh. The average MCC of these three areas for the past 6 months decreased to around $0.80/MWh, but is likely due to above-average hydro conditions this year. The LMP basis of these three areas with the Mid-C SP is relatively small, which means the transmission system in the area as currently configured, including BPA and PacifiCorp assets, is robust. Therefore, the potential congestion risk is low.

Figure 4-3: Historical CAISO day ahead EIM Market LMP

2015	EIM DAY AHEAD MARKET LMP ($/MWh)							
	Klamath Falls Proxy Point		Willamette Valley Proxy Point		Central Oregon Proxy Point		Mid-C Scheduling Point	
	LMP	Congestion	LMP	Congestion	LMP	Congestion	LMP	Congestion
1	29.97	-4.17	29.67	-4.33	29.67	-4.33	32.98	-1.02
2	29.63	-0.27	29.59	-0.25	29.60	-0.25	29.60	-0.26
3	29.43	0.27	29.41	0.29	29.42	0.30	29.40	0.27
4	30.06	1.55	30.08	1.60	30.10	1.63	30.06	1.56
5	31.51	2.47	31.54	2.51	31.56	2.54	31.47	2.45
6	33.24	-1.37	33.25	-1.36	33.22	-1.36	33.22	-1.34
7	32.95	-2.97	32.88	-2.98	32.87	-2.99	32.91	-2.95
8	30.92	-3.40	30.95	-3.38	30.95	-3.39	31.03	-3.34
9	31.73	-1.55	31.76	-1.54	31.76	-1.56	31.84	-1.52
10	28.83	-2.46	28.78	-2.53	28.74	-2.58	28.89	-2.48
11	28.13	-0.02	28.14	-0.02	28.15	-0.02	28.17	-0.02
12	27.25	-0.39	27.25	-0.39	27.26	-0.39	27.24	-0.42
Summary	**30.30**	**-1.04**	**30.28**	**-1.05**	**30.28**	**-1.05**	**30.57**	**-0.76**

2016	EIM DAY AHEAD MARKET LMP ($/MWh)							
	Klamath Falls Proxy Point		Willamette Valley Proxy Point		Central Oregon Proxy Point		Mid-C Scheduling Point	
	LMP	Congestion	LMP	Congestion	LMP	Congestion	LMP	Congestion
1	27.26	-0.38	27.25	-0.38	27.27	-0.38	27.26	-0.40
2	22.89	-0.38	22.86	-0.38	22.88	-0.38	22.88	-0.39
3	18.15	-0.03	18.14	-0.03	18.15	-0.03	18.17	-0.02
4	20.17	1.21	20.16	1.18	20.19	1.19	20.18	1.15
5	19.90	-0.50	19.93	-0.49	19.95	-0.50	19.98	-0.49
6	26.55	-2.30	26.57	-2.32	26.59	-2.32	26.66	-2.29
7	30.56	-1.86	30.63	-1.83	30.66	-1.83	30.75	-1.80
8	33.13	-0.82	33.18	-0.83	33.24	-0.76	33.23	-0.82
9	33.21	0.21	33.28	0.23	32.89	-0.03	33.25	0.20
10	32.11	-0.56	32.17	-0.55	32.30	-0.48	32.18	-0.56
11	28.68	0.17	28.69	0.15	28.71	0.16	27.70	-0.08
12	35.57	0.34	35.60	0.33	35.60	0.33	33.14	0.33
Summary	**27.38**	**-0.41**	**27.40**	**-0.41**	**27.40**	**-0.42**	**27.14**	**-0.43**

2017	EIM AHEAD MARKET LMP ($/MWh)							
	Klamath Falls Proxy Point		Willamette Valley Proxy Point		Central Oregon Proxy Point		Mid-C Scheduling Point	
	LMP	Congestion	LMP	Congestion	LMP	Congestion	LMP	Congestion
1	33.99	0.14	34.03	0.13	34.03	0.13	34.00	0.11
2	27.99	0.60	28.06	0.61	28.05	0.61	27.13	0.51
3	21.37	-0.07	21.42	-0.07	21.42	-0.07	20.52	-0.07
4	20.80	-2.00	20.65	-2.23	20.66	-2.24	19.21	-0.42
5	26.96	-1.06	27.11	-1.04	27.11	-1.04	25.26	-2.88
6	29.87	-2.39	29.95	-2.40	29.93	-2.42	30.03	-2.39
Summary	**26.83**	**-0.80**	**26.87**	**-0.84**	**26.86**	**-0.84**	**26.02**	**-0.87**

4.2.4 Analysis results

The Project is under consideration for possible location in the Klamath Basin, Willamette Valley, or Central Oregon. In the past two years, day-ahead EIM prices at the proxy nodes were robust and there is limited LMP risk or congestion risk in this area. There is the continued possibility of additional wind and solar build-out over the next few years in the Pacific Northwest region. With additional development, congestion may increase in the future years, depending on points of interconnection. However, regional transmission providers, including PacifiCorp and BPA, are actively monitoring congestion to ensure efficient renewable integration and reliable grid operation. Therefore, DNV GL expects congestion risk to be low and at this time does not recommend energy storage on the transmission system for this use case alone.

5 DISTRIBUTION-CONNECTED ENERGY STORAGE SYSTEM ASSESSMENT

The Pacific Power distribution system was assessed using various software, models, and methodologies, depending on the use case or application being investigated. As such, the assessment is segmented by use case.

5.1 Volt/VAR Potential Evaluation Model Development

5.1.1 Inputs required

For this use case, the following inputs were provided by PacifiCorp:

- Load flow model of Redmond feeder 5D22
- Load data for Redmond feeder 5D22

5.1.2 Methodology description

PacifiCorp identified a specific feeder – Redmond 5D22 – as having potential voltage issues which could be solved by the addition of energy storage, using a Volt/VAR control scheme. DNV GL imported the load flow model provided by PacifiCorp to Synergi Electric format for analysis. A load allocation was performed for the forecast peak load for the year 2026. This model provided by PacifiCorp had several large customer loads already identified, along with a number of distribution transformers. The large customer loads were kept constant, and the remaining load required to make up the peak load value was allocated to the distribution transformers in proportion to their kVA rating.

Once the load had been allocated to the model, a load flow analysis was run. The results were used to identify locations on the feeder with high or low voltage. Where there were violations in this peak load case their location was also identified. Where low voltages were identified, an ESS with Volt/VAR control was sited and sized sufficiently to remove the low-voltage violation. The worst voltage violation was addressed first. The system was then re-studied, and any further violations were addressed in turn. The default Volt/VAR curve planned for use in California was assumed, shown in Figure 5-1.

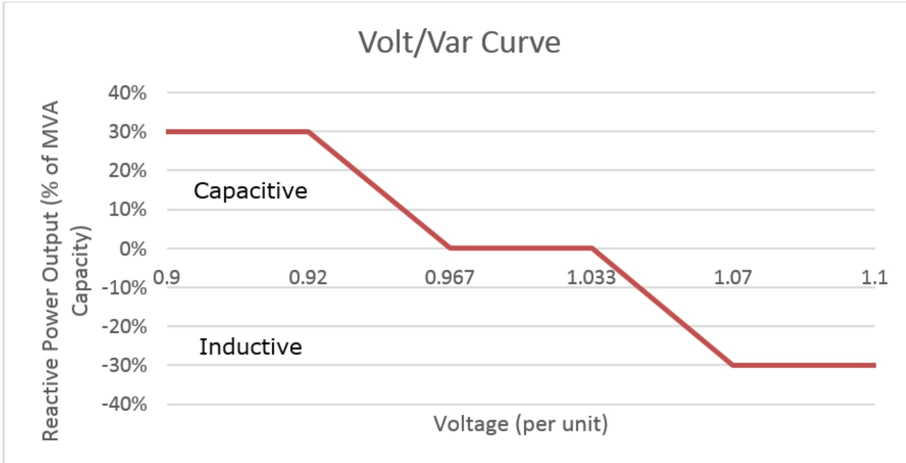


Figure 5-1 Default inverter Volt/VAR curve

5.1.3 Assumptions and methodology limitations

The technical criterion used in this study is that static voltage on the feeder should remain within the range of nominal voltage ±5%. Anything outside this range constitutes a technical violation, and an energy storage unit will be used to attempt to remove the problem.

5.1.4 Modeling results

The base case analysis was conducted using the model provided by PacifiCorp, with load allocation as described in Section 5.1.2 above. The forecast peak load value for 2026 provided by PacifiCorp is 13.95 MW, with a power factor of 0.98. The base case analysis showed all voltages within the range of nominal voltage ±5%, so no voltage violations are present. The feeder voltage profile is shown in Figure 5-2. Voltages in this figure are given on a 120V base, so voltage violations would be above 126V and below 114V. The lowest voltage found here is 115.83V, and the highest is 124.0V.

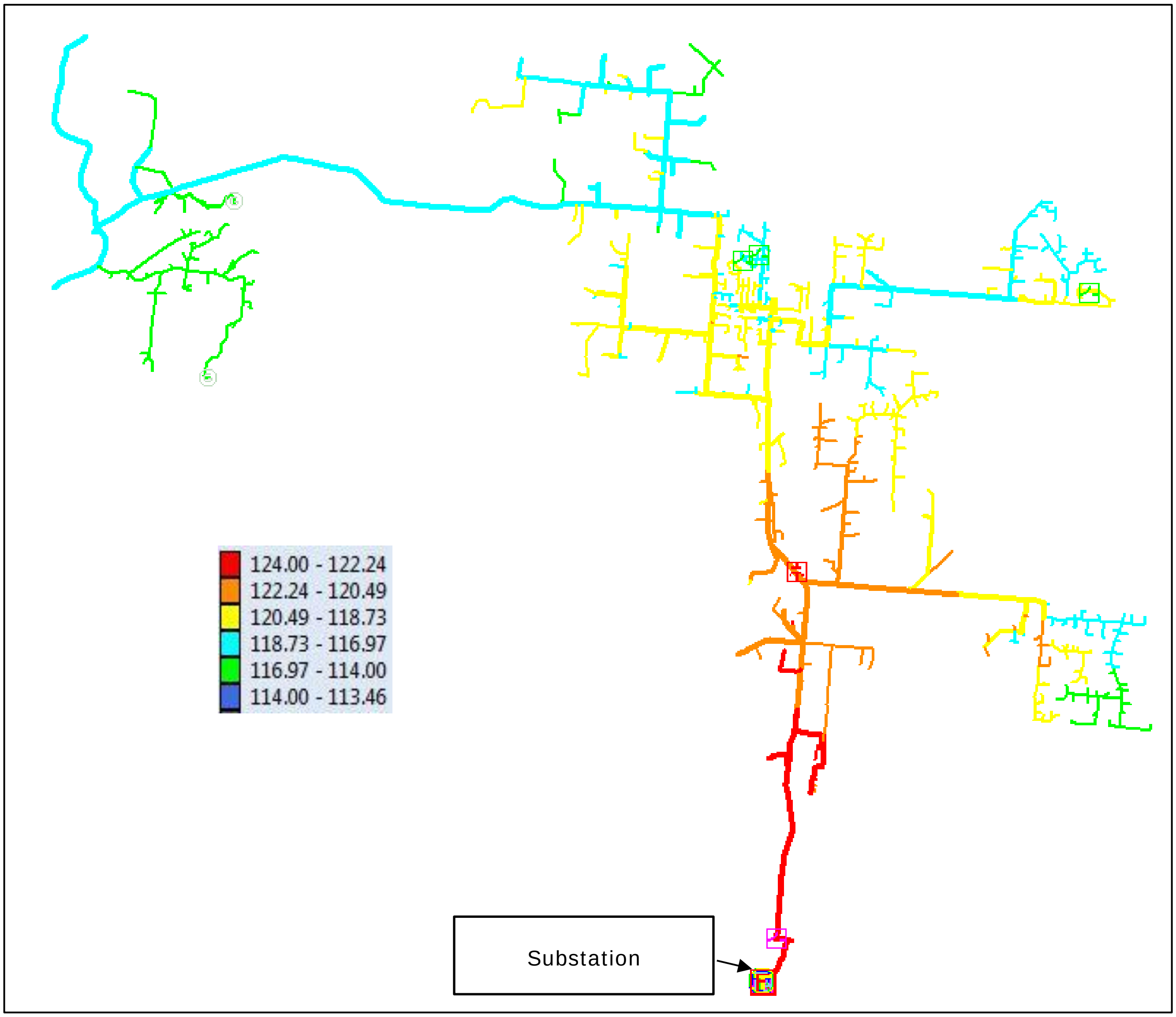


Figure 5-2: Base case Redmond 5D22 voltage profile (voltages reported on a 120V base)

To provide some indications of the potential of ESS to solve voltage problems, a further study was undertaken with reduced feeder voltage. In this case, the voltage setpoint on the feeder voltage regulator was reduced from 124V to 121V. It should be noted that this case is set up for illustrative purposes only, to allow an example of this use-case to be presented. The change in feeder voltage settings are not the real settings for this feeder. The resulting voltage profile is shown in Figure 5-3 on the following page. In this figure, four voltage violations are present.

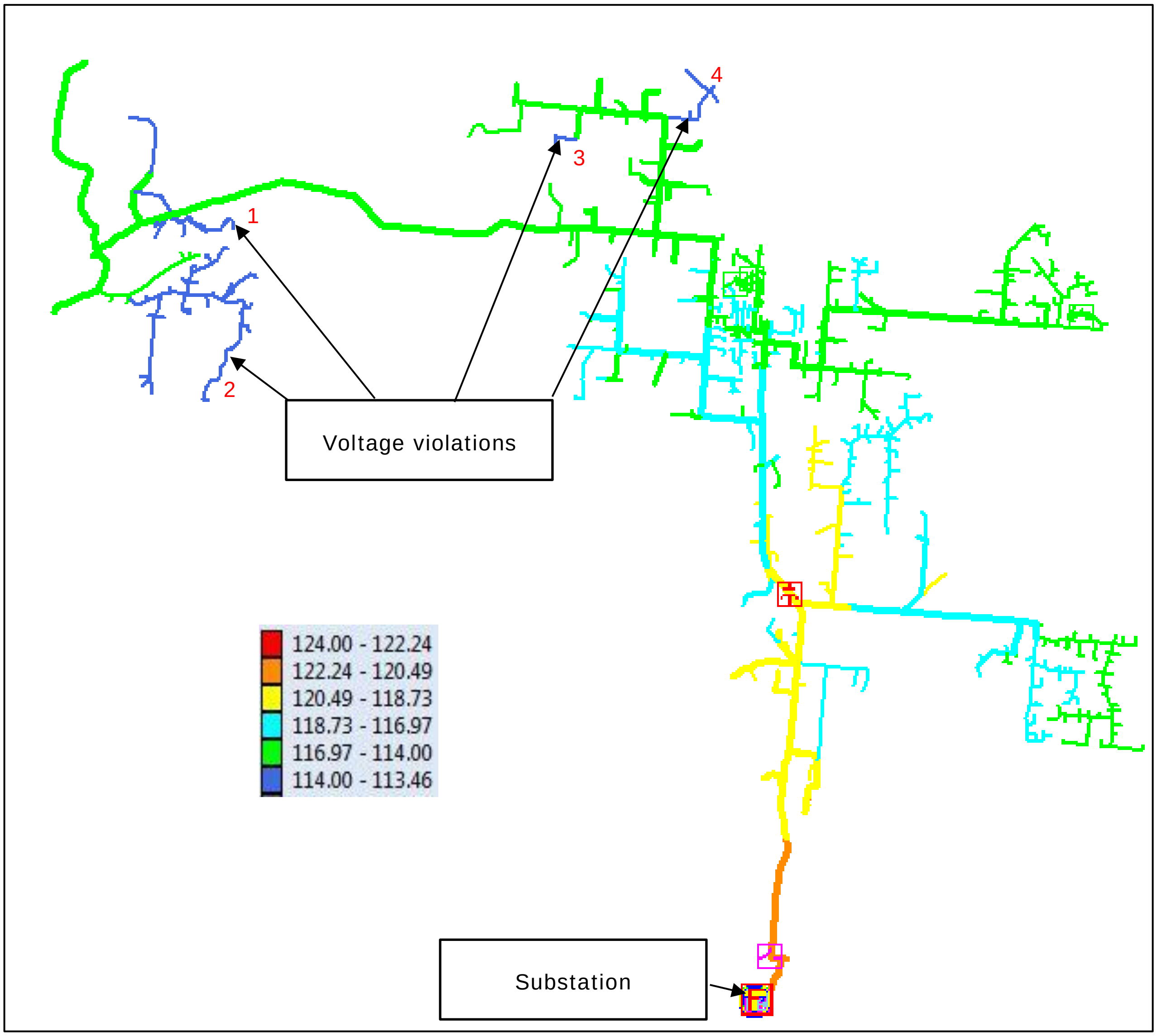


Figure 5-3: Reduced voltage feeder profile (voltages reported on a 120V base)

In Figure 5-3 the four voltage violations are numbered in order of severity. The lowest voltage occurs at point 1, which was found to be at 113.46V on a 120V base. The violations will be addressed in numerical order.

Violation 1:

An energy storage device was placed on the section farthest from the main branch where the voltage violation was present. Its size was increased in 5kVA increments until the voltage violation was removed. It was found that 35kVA was required to increase the voltage on this section from 113.46V to 114.0V, using the volt/VAR profile described previously. Figure 5-4 presents the feeder voltage profile with this energy storage device implemented. Note that this storage device was also sufficient to remove the voltage violations at points 3 and 4 in Figure 5-3.

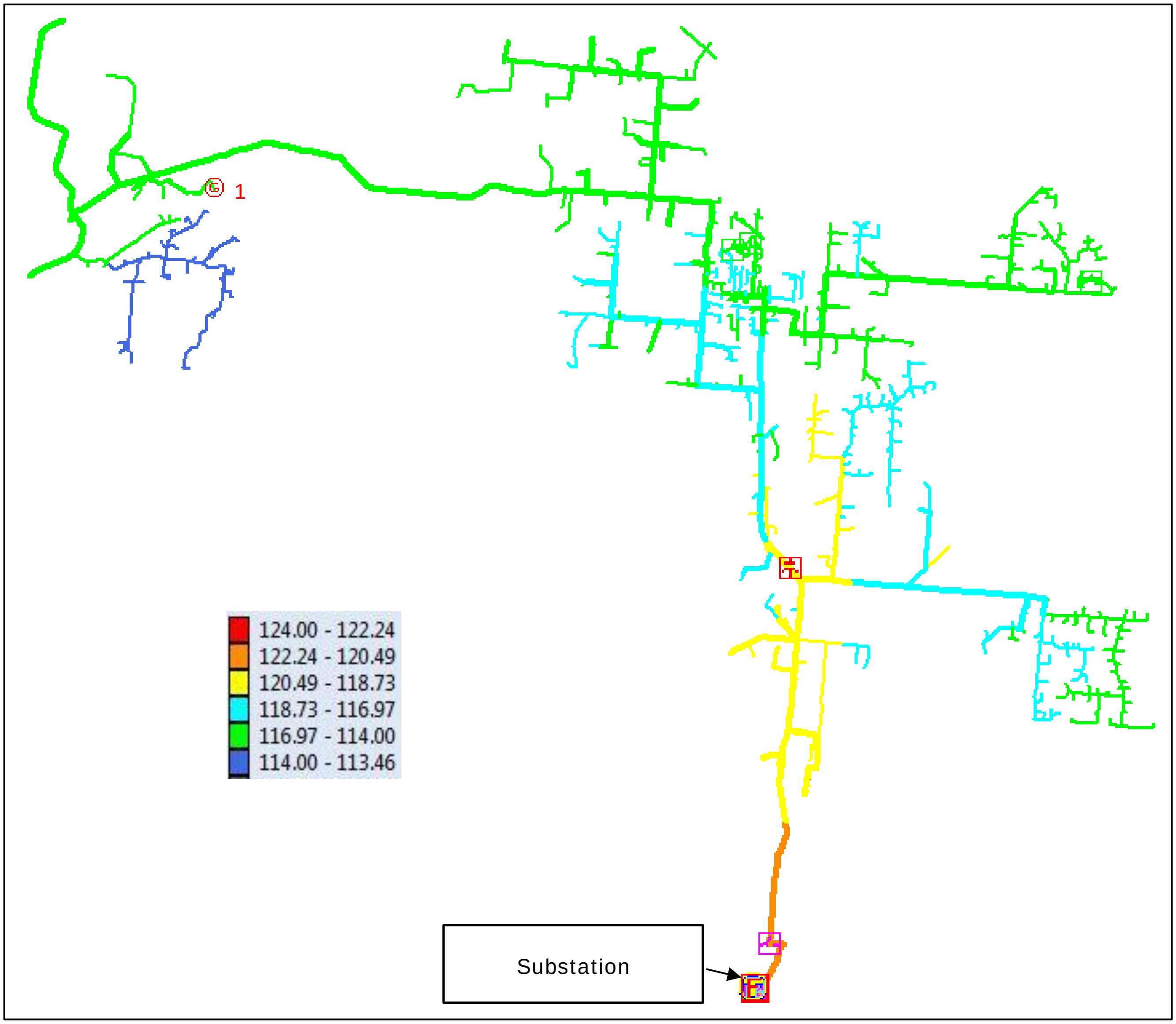


Figure 5-4: Feeder voltage profile with energy storage at violation 1 (voltages reported on a 120V base)

Violation 2:

An energy storage device was placed on the section farthest from the main branch where the voltage violation was present. Its size was increased in 5kVA increments until the voltage violation was removed. It was found that a 17kVA battery was required to increase the voltage on this section from 113.7V to 114.0V, using the volt/VAR profile described previously. Figure 5-5 presents the feeder voltage profile with this energy storage device implemented.

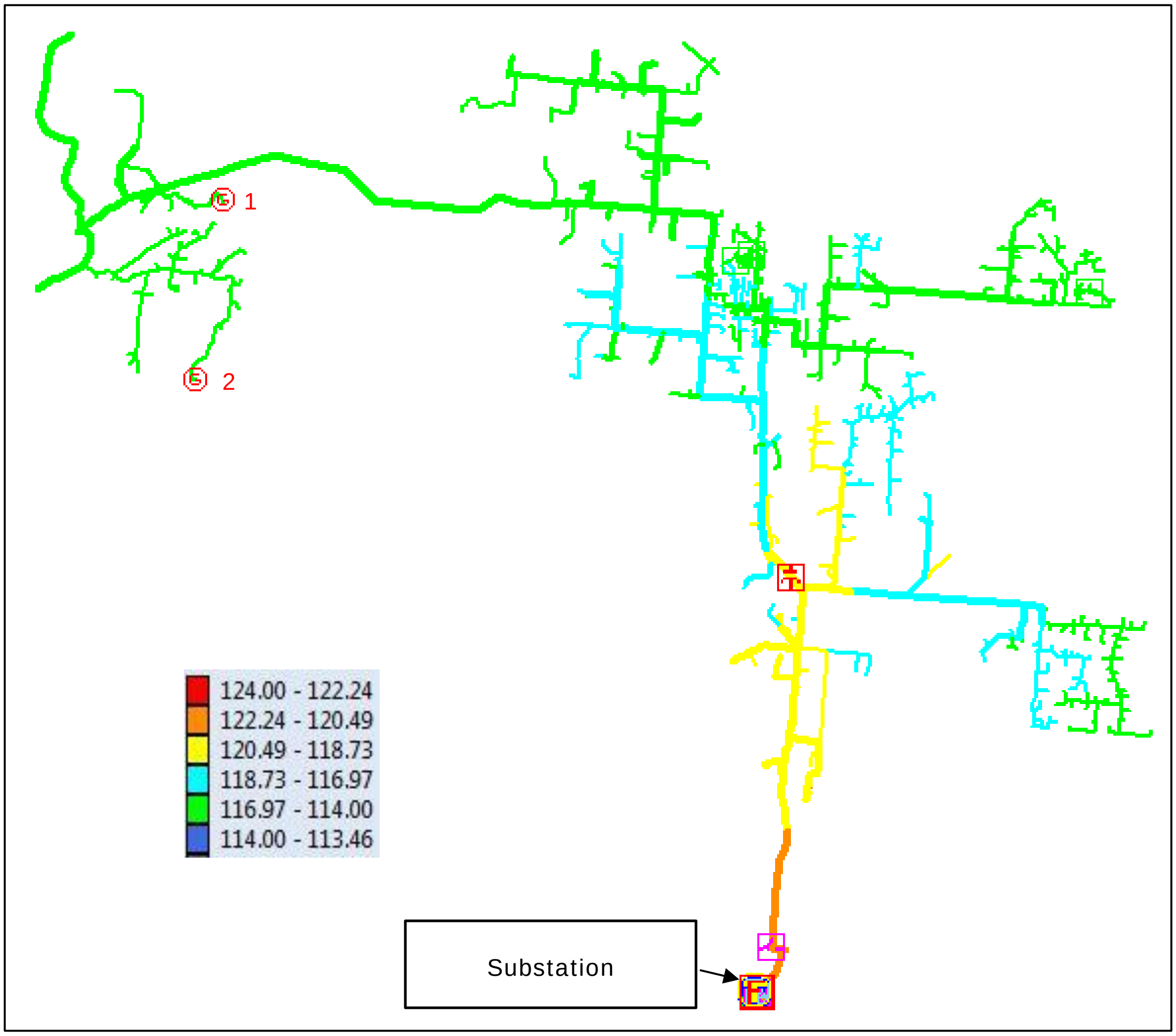


Figure 5-5: Feeder voltage profile with energy storage devices at violation 1 and violation 2 (voltages reported on a 120V base)

With the two energy storage devices installed, there are no more voltage violations on the modeled feeder. Note that the voltage violations did not occur with the voltage regulator set using the given settings (with 124V setpoint and no Line Drop Compensation). If the feeder voltage was to be reduced – for conservation voltage reduction, for example – then the voltage violations described above would be possible.

The results here provide an indication of the energy storage facility size necessary to resolve certain voltage violations on this feeder. For a voltage violation of 0.54V (on a 120V base), 35kVA of storage was required, while 17kVA of storage was required to correct a violation of 0.3V (on a 120V base). These values are dependent upon the feeder loading, and particularly the loading on branches where the violations occur, so other feeders may produce different results. Additionally, the energy storage required could be more distributed than indicated here. Customer-sited storage for this use case is addressed in Section 0.

An alternative solution to a low voltage problem like that described here is placement of capacitor banks. Cost of a capacitor bank on the distribution system can range from a low cost of $15,000 to a high cost of $50,000, with average upgrade costing $20,000. The ESS required in the solution described here would cost approximately $32,000 for the 17kVA battery and around $66,000 for the 35kVA battery, assuming 4 hours of storage (this based on a 2018 cost estimate of $471/kW plus $355/kWh). As such, the capital cost of storage is potentially lower than the cost of traditional voltage mitigation in the first case, and potentially higher in the second case. However, there is the potential for other benefits from customer-sited energy storage such as peak load reduction, which may improve the economics of this option. It should also be noted that energy storage prices are expected to continue to decrease, by up to 12% per year [10].

The relative costs and benefits of the two battery solutions are presented in Table 5-1 below. In this table, the storage benefit is assumed to be the cost (low, average, and high) of the capacitor bank that would otherwise be used to solve the low voltage problem.

Table 5-1: Volt/Var case storage solution results

Storage Size	Storage Cost	Storage Benefit	BCR
17kVA	$32,000	Low: $15,000	Low: 0.47
		Avg: $20,000	Avg: 0.625
		High: $50,000	High: 1.56
35kVA	$66,000	Low: $15,000	Low: 0.23
		Avg: $20,000	Avg: 0.30
		High: $50,000	High: 0.76

5.2 Reliability Potential Evaluation Model Development

5.2.1 Inputs required

For this use case, the following inputs were provided by PacifiCorp:

- Load flow model of Hillview feeder 4M182;
- Load data for Hillview feeder 4M182;
- Reliability data for Hillview feeder 4M182.

5.2.2 Methodology description

PacifiCorp identified a specific feeder – Hillview 4M182 – as having potential reliability issues which could be reduced or relieved by the addition of energy storage. In this case, the ESS was intended to act as an alternate source in the event of an outage on the feeder, with the intention of improving the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) for the circuit. The ESS was located and sized such that it could serve the peak load of all the customers on the circuit. The ESS was sited at the end of the feeder furthest from the Hillview substation, as shown in Figure 5-6.

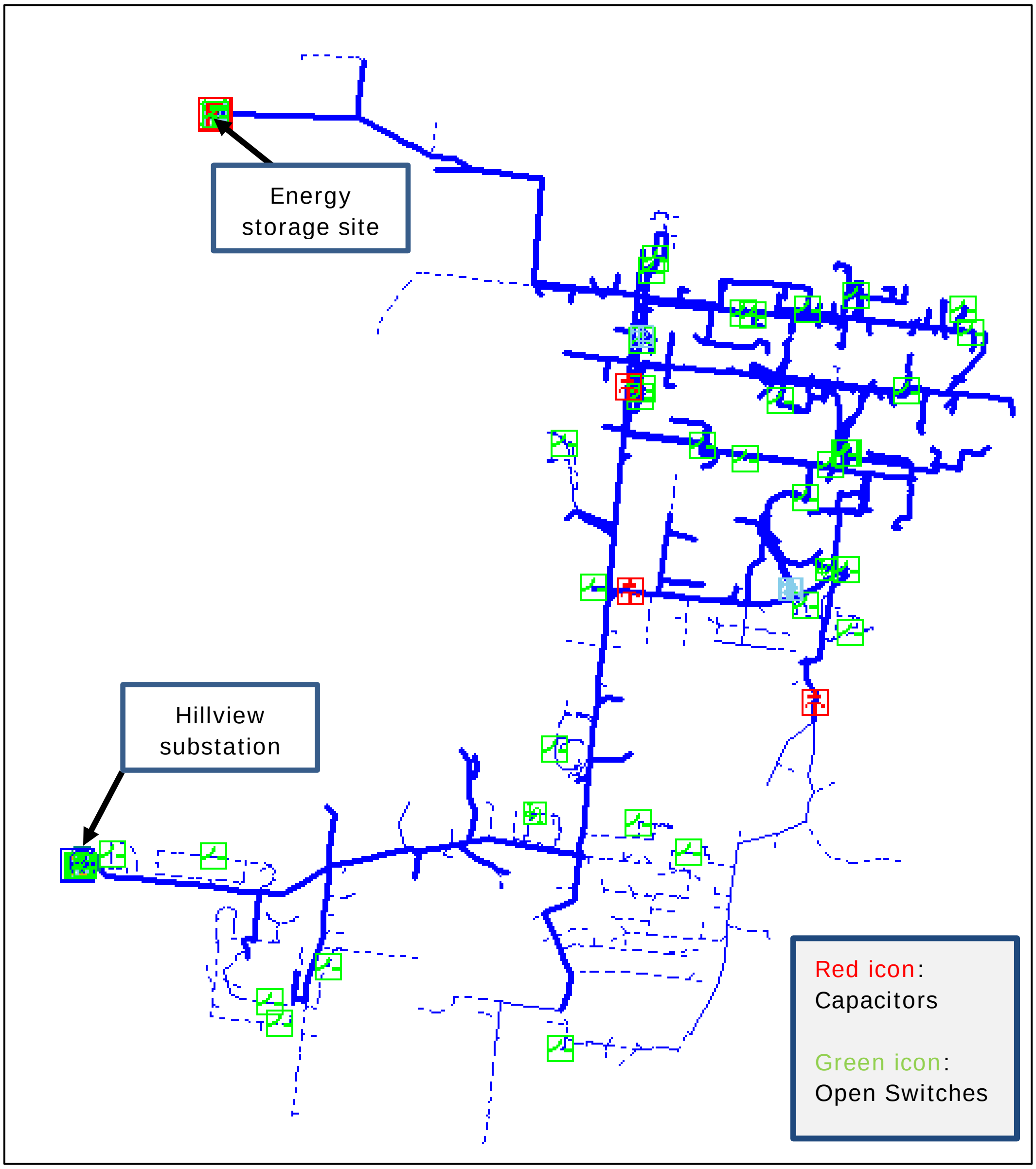


Figure 5-6 Hillview feeder

The load flow model of the circuit was imported to Synergi Electric format. The peak load provided by PacifiCorp was allocated based on distribution transformer sizing in the model. Failure and outage data was provided by PacifiCorp for the circuit, including location of outages, number of customers affected, and customer minutes interrupted. This data was used to derive failure rates and repair times for the components of the system due to different outage causes. An initial reliability analysis was run with the system as it exists at present, followed by an analysis with the energy storage system setup as an alternative source in the model. The SAIDI and SAIFI numbers could then be compared between the cases.

5.2.3 Assumptions and methodology limitations

The methodology involves the creation of an 'Exposure Zone' in Synergi Electric. An Exposure Zone defines a set of failure rates and repair times for different outage causes on the system. Failure rates are defined as the number of failures per year per mile of line. The values used for these failure rates are derived from the outage data provided by PacifiCorp, with the assumption that the failure rate is constant across the feeder (i.e. every section has the same probability of failure).

5.2.4 Modeling results

The outage data provided by PacifiCorp for the Hillview feeder was analyzed by DNV GL, and produced the failure rate data shown in Table 5-2 for various categories of outage.

Table 5-2: Failure rate data derived from outage data for Hillview circuit

Cause	Failures	Failures/yr	Failures/yr/mile	Average Repair time (hours)
Trees	10	1	0.0797	3.1033
Equipment failure	29	2.9	0.2311	4.9791
Planned	17	1.7	0.1355	3.7579
Animals	12	1.2	0.0956	1.3565
Other	15	1.5	0.1195	1.1884
Interference	2	0.2	0.0159	1.2825
Weather	5	0.5	0.0398	22.3860

In addition to these circuit-wide values, outage due to loss of source was included at 0.6 failures per year.

With the ESS disconnected to the Hillview feeder, a base case analysis was run. The results for this base case were:

- SAIFI: 4.39 interruptions
- SAIDI: 473.78 minutes

The ESS was then added to the model at the end of the circuit furthest from the Hillview substation, and connected to the feeder through a normally-open automatic switch. The reliability analysis was repeated with this setup, and the following results were obtained:

- SAIFI: 4.39 interruptions
- SAIDI: 473.76 minutes

There is no reduction in SAIFI, as the number of interruptions remains the same. The reduction in SAIDI is also negligible at 0.004%. The reasons for the minimal impact on the circuit reliability values may be due to the circuit having a large amount of connectivity already, indicating that outages other than source outages can be mitigated quickly by circuit re-configuration through other automated switching processes. As the circuit configuration and customer distribution has a significant impact on SAIDI and SAIFI results, similar analyses on other circuits may produce different results in terms of the effectiveness of energy storage systems on improved reliability. Reliability benefits of an ESS at a customer site on this circuit is discussed in Section 6.1.

5.3 Upgrade Deferral Potential Evaluation Model Development

5.3.1 Inputs required

Technical Inputs

For this use case, PacifiCorp provided data for four substations which are likely to be overloaded soon or in the future. These substations are: Hillview, Independence, Lyons, and Redmond. Table 5-3 Substations used in upgrade deferral use case shows the feeders associated with each substation.

Table 5-3 Substations used in upgrade deferral use case with associated feeders

Substation	Feeder No.
Hillview	4M182
Independence	4M22
	4M25
Lyons	4M70
	4M120
Redmond	5D22

PacifiCorp provided the following inputs for each substation:

- Substation-level 15-min load profile for 2016-2026
- Summer and winter load-growth rates
- Existing substation transformer ratings
- Feeder-level summer and winter power factors for feeders 4M70 and 4M120
- Substation transformer upgrade cost

Table 5-4 presents the summer and winter load growth rates for each substation, as well as existing substation transformer ratings.

Table 5-4: Summer and winter load growth rates and transformer ratings

Substation	Feeder	Annual Load Growth Rate		Transformer Rating (MW)
		Summer	Winter	
Hillview	4M182	2.5%	1.8%	19.00
Independence	4M22 and 4M25	1.8%	1.3%	23.75
Lyons	4M70	1.8%	2.0%	23.37
	4M120	1.6%	0.75%	
Redmond	5D22	5.0%	1.0%	23.75

DNV GL processed the load data provided by PacifiCorp to extend load forecast to 2037 and convert 15-min load profiles to hourly profiles. Table 5-5 shows the annual peak load for each substation over a 20-year period from 2018 to 2037. The data in Table 5-5 shows that Hillview will be overloaded and require upgrades in 2023 while Independence and Lyons will be overloaded and require upgrades starting in 2018. It was assumed that the overloading will be mitigated by other alternative methods until the end of 2017. Redmond does not need an upgrade for at least 20 years. These estimates assume that an upgrade will not be required until load reaches 100% of substation transformer capacity. If PacifiCorp decides to reserve some capacity to account for load growth uncertainties, these upgrades should take place sooner than stated above.

Table 5-5: Substation-level annual peak load (MW)

Substation	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hillview	17.74	18.18	18.64	19.10	19.58	20.07	20.57	21.09	21.61	22.16
Independence	27.70	28.71	29.30	29.83	30.11	30.40	30.69	30.99	31.29	31.70
Lyons	27.30	27.66	28.02	28.38	28.76	29.13	29.52	29.91	30.30	30.70
Redmond	9.41	9.50	9.60	9.69	9.79	9.89	9.99	10.09	10.19	10.29
	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Hillview	22.71	23.28	23.86	24.46	25.07	25.69	26.34	26.99	27.67	28.36
Independence	32.11	32.53	32.95	33.53	34.14	34.75	35.38	36.01	36.66	37.32
Lyons	31.11	31.53	31.95	32.38	32.82	33.26	33.71	34.17	34.63	35.11
Redmond	10.39	10.50	10.60	10.71	10.81	11.13	11.69	12.28	12.89	13.53

Other Input Assumptions

Inputs required for the economic assessment of the storage system are as shown in Table 5-6:

Table 5-6: Other Input Assumptions

Parameter	Value
Storage round-trip efficiency (%)	80%
Storage calendar life (years)	10
Transformer life (years)	50

5.3.2 Methodology description

A linear programming algorithm is used to determine the optimal hourly dispatch of energy storage based on a deterministic load profile, with the objective of minimizing overall peak load of the year. The constraints used in the optimization ensure that storage charge and discharge levels are within its power limits. Also, state of charge is monitored and updated each hour based on the charge and discharge levels and storage efficiency.

The optimization is run for every year within project analysis period. Outputs include hourly storage dispatch profile, number of years of upgrade deferral, and days on which storage is dispatched for peak shaving. It is important to note that once storage cannot reduce the load below transformer rating, it will not be dispatched for deferral application anymore. However, storage remains on the feeder until the end of its calendar life. We will evaluate the benefit from using storage for frequency response when deferral is not possible anymore.

Load reduction optimization is performed for all energy storage sizing scenarios.

The optimization results are then fed into a financial model to estimate costs and benefits associated with storage sizing scenario. Two financial metrics are used for comparing the cost effectiveness of scenarios: net present value of total costs and BCR, which is NPV of total benefits over NPV of total costs.

Both storage capital costs and transformer upgrade costs are calculated using an equity draw and debt payment structure. Transformer upgrade deferral benefit is evaluated by calculating the impact of moving transformer upgrade payment by the number of years of deferral.

5.3.3 Modeling results

Modeling results are presented for the Hillview, Independence, and Lyons substations below.

Hillview Substation Scenarios and Results

To maximize deferral benefits, we assumed that storage will be installed in 2023, the year in which Hillview transformer will be overloaded. Table 5-7 presents the storage sizing scenarios evaluated for Hillview substation. The possible number of years of deferral given optimal dispatch of energy storage and perfect forecast of feeder load profile are shown in Table 5-7 as well.

Table 5-7: Hillview storage sizing scenarios and year of deferral

Scenario #	ES Power Rating (MW)	ES Energy Capacity (MWh)	Years of Deferral
Scenario 1	1	2	2
Scenario 2	1	4	2
Scenario 3	2	4	4
Scenario 4	2	8	4
Scenario 5	4	8	7
Scenario 6	4	16	8
Scenario 7	6	12	9
Scenario 8	6	24	10
Scenario 9	8	8	7

Table 5-8 presents annual peak load for the base (no storage) scenario and all storage sizing scenarios.

Table 5-8: Hillview substation base and reduced peak load (MW)

Scenario	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Base	19.1	19.6	20.1	20.6	21.1	21.6	22.2	22.7	23.3	23.9	24.5	25.1	25.7	26.3	27.0
1	18.1	18.6	20.1	20.6	21.1	21.6	22.2	22.7	23.3	23.9	24.5	25.1	25.7	26.3	27.0
2	18.1	18.6	20.1	20.6	21.1	21.6	22.2	22.7	23.3	23.9	24.5	25.1	25.7	26.3	27.0
3	17.1	17.6	18.1	18.6	21.1	21.6	22.2	22.7	23.3	23.9	24.5	25.1	25.7	26.3	27.0
4	17.1	17.6	18.1	18.6	21.1	21.6	22.2	22.7	23.3	23.9	24.5	25.1	25.7	26.3	27.0
5	15.9	16.4	16.9	17.3	17.8	18.3	18.8	22.7	23.3	23.9	24.5	25.1	25.7	26.3	27.0
6	15.1	15.6	16.1	16.6	17.1	17.6	18.2	18.7	23.3	23.9	24.5	25.1	25.7	26.3	27.0
7	15.0	15.5	15.9	16.4	16.9	17.3	17.8	18.3	18.9	23.9	24.5	25.1	25.7	26.3	27.0
8	14.0	14.4	14.8	15.1	15.5	16.0	16.4	16.8	17.3	17.9	24.5	25.1	25.7	26.3	27.0
9	15.9	16.4	16.9	17.3	17.8	18.3	18.8	22.7	23.3	23.9	24.5	25.1	25.7	26.3	27.0

Independence Substation Scenarios and Results

Table 5-9 presents the storage sizing scenarios evaluated for Independence substation. The possible number of years of deferral given optimal dispatch of energy storage and perfect forecast of feeder load profile are shown in Table 5-9 as well.

Table 5-9: Independence Storage Sizing Scenarios and Year of Deferral

Scenario #	ES Power Rating (MW)	ES Energy Capacity (MWh)	Years of Deferral
Scenario 1	6	24	1
Scenario 2	10	20	1
Scenario 3	10	60	2

Table 5-10 presents annual peak load for the base (no storage) scenario and all storage sizing scenarios.

Table 5-10: Independence Substation Base and Reduced Peak Load (MW)

Scenario	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base	27.7	28.7	29.3	29.8	30.1	30.4	30.7	31.0	31.3	31.7	32.1	32.5	32.9	3.53	34.1
1	23.5	28.7	29.3	29.8	30.1	30.4	30.7	31.0	31.3	31.7	32.1	32.5	32.9	3.53	34.1
2	23.7	28.7	29.3	29.8	30.1	30.4	30.7	31.0	31.3	31.7	32.1	32.5	32.9	3.53	34.1
3	22.8	23.7	29.3	29.8	30.1	30.4	30.7	31.0	31.3	31.7	32.1	32.5	32.9	3.53	34.1

Lyons Substation Scenarios and Results

Table 5-11 presents the storage sizing scenarios evaluated for Lyons substation. Possible number of years of deferral given optimal dispatch of energy storage and perfect forecast of feeder load profile are shown in Table 5-11 as well.

Table 5-11: Lyons Storage Sizing Scenarios and Year of Deferral

Scenario #	ES Power Rating (MW)	ES Energy Capacity (MWh)	Years of Deferral
Scenario 1	6	36	1
Scenario 2	8	32	1
Scenario 3	8	48	2
Scenario 4	10	60	3

Table 5-12 presents annual peak load for the base (no storage) scenario and all storage sizing scenarios.

Table 5-12: Lyons Substation Base and Reduced Peak Load (MW)

Scenario	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base	27.3	27.7	28.0	28.4	28.8	29.1	29.5	29.9	30.3	30.7	31.1	31.5	31.9	32.4	32.8
1	23.2	27.7	28.0	28.4	28.8	29.1	29.5	29.9	30.3	30.7	31.1	31.5	31.9	32.4	32.8
2	23.2	27.7	28.0	28.4	28.8	29.1	29.5	29.9	30.3	30.7	31.1	31.5	31.9	32.4	32.8
3	23.0	23.3	28.0	28.4	28.8	29.1	29.5	29.9	30.3	30.7	31.1	31.5	31.9	32.4	32.8
4	22.8	23.1	23.4	28.4	28.8	29.1	29.5	29.9	30.3	30.7	31.1	31.5	31.9	32.4	32.8

5.3.4 Financial Results

General input assumptions used in distribution upgrade deferral financial analysis are shown in Table 5-13. Transformer upgrade costs were provided by PacifiCorp for three substations. Storage capital cost values for 2018 and 2021 are derived from Table 3-1.

Table 5-13: Distribution Upgrade Deferral Financial Assumptions

Parameter	Value
Storage Fixed O&M Cost Annual Escalation Rate (%)	2%
Hillview Transformer Upgrade Cost ($)	$3,000,000
Independence Transformer Upgrade Cost ($)	$2,760,000
Lyons Transformer Upgrade Cost ($)	$3,980,000
Transformer Annual O&M Cost ($)	$8,500

Storage capital cost and transformer upgrade costs are calculated using an equity draw and debt payment structure. Storage fixed O&M cost is an annual payment which increases every year with a rate of 2%.

Deferral benefit is simply the value of money realized by PacifiCorp because of moving upgrade cost stream by the number of deferral years. And finally, we assumed that transformer operations and maintenance (O&M) cost is avoided for the years that upgrade is deferred. To illustrate the cashflow analysis, an example case is shown in Table 5-14.

Table 5-14: Cashflow example - Hillview scenario 1

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ES Capital Cost - Equity	($618.4)	-	-	-	-	-	-	-	-	-
ES Capital Cost – Debt	($76.6)	($76.6)	($76.6)	($76.6)	($76.6)	($76.6)	($76.6)	($76.6)	($76.6)	($76.6)
ES Fixed O&M Cost	($6.4)	($6.5)	($6.6)	($6.8)	($6.9	($7.0)	($7.2)	($7.3)	($7.5)	($7.6)
Deferral Benefit – Equity	$1,543.2	-	-	($1,543.2)	-	-	-	-	-	-
Deferral Benefit - Debt	$83.0	$83.0	-	-	-	-	-	-	-	-
Avoided TX O&M Cost	$8.5	$8.5	-	-	-	-	-	-	-	-

Two financial metrics are used to evaluate sizing scenarios and compare them against each other. These metrics are NPV of total costs and benefits, and BCR. BCR is calculated by dividing the present value of total benefits by the present value of total costs.

Hillview Substation Financial Results

For Hillview substation, DNV GL also evaluated the benefit from bundling upgrade deferral application with frequency response in the years in which storage is not dispatched for deferral. Two prices were assumed for capacity in frequency response application. Financial metrics for these cases are presented in Table 5-15.

Table 5-15: Hillview Transformer Upgrade Deferral Financial Summary

Scenario	Deferral Only		Deferral + Frequency Response ($44.4/kW-year)		Deferral + Frequency Response ($81/kW-year)	
	NPV	BCR	NPV	BCR	NPV	BCR
1	$(653,017)	0.36	$(397,246)	0.61	$(188,910)	0.81
2	$(1,180,819)	0.23	$(925,047)	0.40	$(716,711)	0.53
3	$(1,349,450)	0.34	$(989,393)	0.51	$(697,595)	0.66
4	$(2,405,053)	0.22	$(2,044,995)	0.34	$(1,753,198)	0.43
5	$(2,971,961)	0.27	$(2,639,614)	0.35	$(2,375,665)	0.41
6	$(4,963,582)	0.20	$(4,744,847)	0.23	$(4,574,552)	0.26
7	$(4,770,846)	0.22	$(4,602,627)	0.24	$(4,478,980)	0.26
8	$(7,832,398)	0.15	$(7,814,178)	0.15	$(7,814,178)	0.15
9	$(4,922,077)	0.18	$(4,919,139)	0.29	$(4,919,139)	0.38

Independence Substation Financial Results

Financial metrics for Independence substation are presented in Table 5-16. Low benefit-to-cost ratios are due to low transformer upgrade costs compared to the cost of storage as well as the power rating and energy capacity needed to reduce peak load below transformer power capacity.

Table 5-16: Independence Transformer Upgrade Deferral Financial Summary

Scenario	NPV	BCR
1	$(11,813,645)	0.02
2	$(12,491,664)	0.01
3	$(26,961,598)	0.01

Lyons Substation Financial Results

Financial metrics for Lyons substation are presented in Table 5-17.

Table 5-17: Lyons Transformer Upgrade Deferral Financial Summary

Scenario	NPV	BCR
1	$(16,150,812)	0.01
2	$(15,757,488)	0.02
3	$(21,386,095)	0.02
4	$(26,635,601)	0.03

While independently the deferral use case does not reach a BCR = 1, when stacked with other applications (such as frequency response as noted in the Hillview scenarios), the economics improve. Additionally, if transformer upgrade costs are found to be greater than cited, the economic calculations can be updated to reflect this and provide more favorable BCR.

5.4 System Level Distribution Upgrade Deferral Opportunities

Beyond the specific deferral case studies evaluated here for the Hillview, Independence, and Lyons substations, DNV GL performed a high-level assessment of the system-wide deferral opportunities across PacifiCorp's Oregon service territory. The objective of this system-wide evaluation is to assess the number of potential deferral opportunities which can be facilitated by energy storage and to provide an estimate of the total energy storage capacity required to enable these deferral opportunities.

5.4.1 Inputs required

This analysis requires a list of all substations in PacifiCorp's Oregon territory with the following data for each substation:

- Base 2016 loading level
- Substation capacity rating
- Load growth projections for 2017-2026

PacifiCorp provided a database of the 271 substations across its Oregon territory along with the above data for each substation. A sample anonymized excerpt of this data set is shown in Table 5-18.

Table 5-18: Sample excerpt of the PacifiCorp Oregon substation database

Bus #	Substation Name	Base 2016 Loading (MW)	Low Side Power Factor	Substation Capacity (MVA)	2017 (MW)	2018 (MW)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)	2026 (MW)
1001	Sub X	8.97	0.97	13.13	9.06	9.15	11.14	11.26	11.37	11.48	11.60	11.71	11.83	11.95
1001	Sub Y	8.03	0.96	13.13	8.10	12.36	12.46	12.56	12.66	12.76	12.87	12.97	13.07	13.18
1001	Sub Z	7.00	0.98	17.54	7.04	7.07	7.11	7.14	7.18	7.21	7.25	7.28	7.32	7.36

5.4.2 Methodology description

This high-level analysis is designed to identify the following:

- The number of substations in the PacifiCorp Oregon service territory which are projected to require upgrade within the next 10 years
- The total transformer capacity corresponding to these identified substations
- The total amount of projected storage capacity to address deferral opportunities across all identified substations

To identify the number of substations which are projected to require an upgrade within the next 10 years, the projected yearly load growth from 2017-2026 for each substation was compared against its respective capacity rating, accounting for power factor. For each substation identified as requiring an upgrade from 2017-2026, the transformer capacity was recorded.

Optimal sizing of energy storage for upgrade deferral requires detailed analysis as presented in Section 4.3. While there are no general rules-of-thumb to specify the energy storage capacity for upgrade deferral, the detailed analyses in Section 4.3 can provide a reasonable range of storage-to-transformer power capacity ratios which provide optimal BCR. Looking across the results from the Hillview deferral analyses, which were assumed to have similar load growth assumption, the storage-to-transformer power capacity ratios with the best BCRs ranged from 0.05 to 0.20. Barring a detailed analysis on every candidate substation, these values provide a reasonable range of capacity ratios for determining the total energy storage capacity required to address deferral opportunities across all candidate substations. This range of storage-to-transformer power capacity ratios is also in line with DNV GL's observations obtained while performing upgrade deferral analysis for two California IOUs and the California Energy Commission [11].

5.4.3 System Level Energy Storage Potential for Upgrade Deferral

Evaluation of the 271 substations across PacifiCorp's Oregon service territory resulted in 46 substations with projected overloads occurring over the time-period of 2017 to 2026. These 46 substations represent 936 MVA of total substation transformer capacity. Using an assumed range of 0.05 to 0.20 as the storage-to-substation power capacity ratio, this represents 47 MW to 187 MW of potential energy storage power capacity for distribution upgrade deferral. Assuming 2-hour duration for each system, a duration selected based on the most cost-effective of the deferral cases studied in Section 5.3, this corresponds to 94 MWh to 374 MWh of storage energy capacity.

6 CUSTOMER-SITED ENERGY STORAGE SYSTEM ASSESSMENT

Energy storage located at customer sites provide unique opportunities to locate energy sources closer to demand than possible with traditional substations. These devices, especially if paired with on-site generation, can provide additional local reliability and other ancillary grid services. Further, if owned by the customer, additional cost saving benefits may be garnished by the customer with time of use load shift and demand reduction. This section details one customer-sited, utility owned case, under various conditions, and also discusses the potential to distribute and aggregate previously modeled cases for behind the meter installations.

6.1 Customer-sited, Utility Owned Storage Potential Evaluation Model Development

This use case examines the cost-effectiveness of an ESS deployed on the distribution system and performing customer benefit applications. The system is deployed on the utility side of the meter at a [redacted] that is located at the end of the [redacted] distribution circuit. This use-case evaluates the following single and stacked applications:

- ESS providing reliability to customer loads under distribution or transmission system outage.
- ESS providing reliability to customer loads, substation upgrade deferral and primary frequency response

6.1.1 Inputs required

- Circuit topology showing feeders, switchgear, metering, distributed assets, and load centers on the campus
- Customer energy consumption and peak demand by facility
- Distribution and transmission circuit outage data
- Distribution circuit loading conditions to evaluate requirement for deferral
- Frequency event data

6.1.2 Methodology description

In this use case, customer facilities are aggregated into two clusters as follows:

- [redacted]
- [redacted]

We assume that the ESS is interconnected to the [redacted] distribution circuit such that under outage conditions, the ESS can be islanded with either one of the customer facility groups. Hence, two separate reliability scenarios can be evaluated:

- Distribution outage – In this scenario there is an outage upstream on the [redacted] circuit and the [redacted] facilities are switched to the [redacted] circuit. The [redacted] are islanded and supplied by the energy storage system.
- Transmission outage – In this scenario, supply is lost on the [redacted] and [redacted] circuits. If the [redacted] has critical load requirements, such as a scheduled event, the energy storage system is islanded with the [redacted] facilities. The loads on the [redacted] circuit are not supplied.

6.1.2.1 Load modeling

Monthly energy consumption data and annual peak demand was provided for each facility. Table 6-1 gives an overview of the load requirements at the [redacted] loads. It was assumed that the coincident peak demand of the [redacted] is equal to the sum of the peak demand of the individual buildings. The coincident peak demand of the [redacted] loads was assumed to be [redacted] of annual peak demand.

Table 6-1: Overview of energy consumption and demand at customer facilities

	[redacted]	[redacted]	[redacted]
Annual Energy Consumption (kWh)	[redacted]	[redacted]	[redacted]
Sum of annual peak demand (kW)	[redacted]	[redacted]	[redacted]
Assumed coincident peak demand (kW)	[redacted]	[redacted]	[redacted]

For evaluating customer reliability, hourly consumption data for each customer group is required over a calendar year. To generate representative hourly consumption profiles, energy consumption was simulated using the software *EnergyPlus* in statistically benchmarked buildings equivalent to ASHRAE 90.1 2013 – code efficiencies and requirements. The location of statistically benchmarked buildings was assumed to be Portland, Oregon. [redacted] was used to characterize the consumption profile at the [redacted] facilities [redacted]. The consumption profile of a [redacted] building was used as a representative of [redacted]. The simulated consumption profiles were then calibrated to actual meter data by the following steps:

- Consumption profiles were aligned such that the peak demand hour on the [redacted] circuit corresponds to the peak demand hour on the simulated [redacted] load profiles. The peak demand hour on the [redacted] loads was selected as September 24th, 5 pm, corresponding to an [redacted].
- Simulated consumption profiles were calibrated such that annual peak demand matched the assumed coincident demand of the load clusters given in Table 6-1.
- For each month, the simulated consumption profiles were calibrated such that the total energy requirement of the month matched the metered energy for the load clusters. Hourly consumption was discretized into ten samples – from 0% to 100% of monthly peak demand. The consumption

within each sample was adjusted per seasonal variations and calendar events. Figure 6-1 shows an example of the adjustment process to match metered consumption data at the [redacted] facilities for Jan 2016. The total monthly consumption of the load profile generated from *EnergyPlus* aligned to [redacted] peak demand hour and calibrated to an annual peak demand [redacted] is shown in blue. The monthly consumption in Jan 2016 under this profile is [redacted], whereas the meter data recorded [redacted]. The orange line shows the adjustment to the simulated profile to increase total monthly consumption to meter data while maintaining the load characteristics.

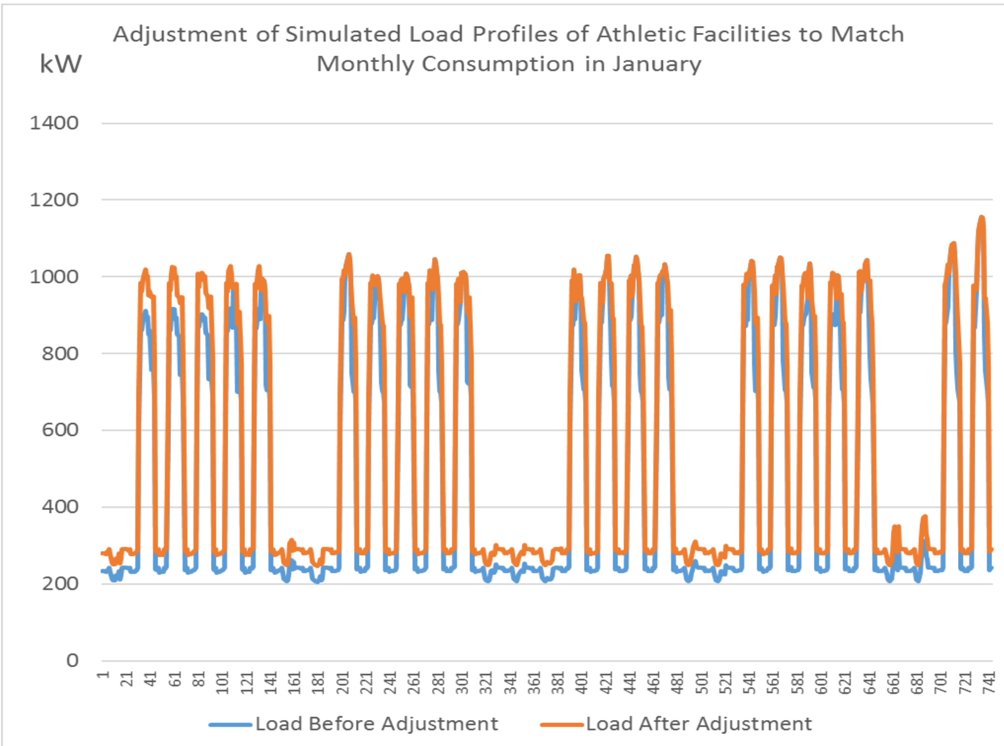


Figure 6-1: Adjustment of simulated load profiles for athletic facilities to match metered consumption in January 2016

6.1.2.2 Solar PV modeling

Solar photovoltaic (PV) installation is planned at several customer facilities within the microgrid. [redacted] To evaluate the reliability impact of combining the ESS with customer sited solar PV production, DNV GL developed hourly production profiles of the customer sited PV.

Since details of specific array and mounting technology were not available, DNV GL simulated a [redacted] ground mounted solar PV installation at the approximate location of the customer facilities. The simulation was performed using the commercially available software *Helioscope* based on generic, industry standard technology assumption and parameters shown in Table 6-2.

Table 6-2: Solar PV simulation parameters

Parameter	Value
Module DC Nameplate	[redacted]
Inverter AC Nameplate	[redacted]
DC to AC ratio	1.28
Annual AC production	[redacted]
Racking and Orientation	Fixed tilt / vertical

Figure 6-2 shows an overview of simulated solar PV production and the source of system losses. The peak coincident PV production was derived to be [redacted]

[redacted]

Figure 6-2: Overview of simulated Solar PV production by month and sources of system loss

6.1.2.3 Outage characterization

DNV GL analyzed data on 96 outage events from 2006 to 2017. The data comprised 90 distribution system events on the [redacted] circuit and 6 transmission events that also caused load loss on the distribution circuit. Table 6-3 shows the characteristics of all outages on the [redacted] circuit. The customer average annual interruption duration is calculated as 146.4 minutes. Since the [redacted] are located at the end of the [redacted] circuit and susceptible to any upstream outage on the distribution system, it is assumed that the average annual interruption duration at those facilities is 146.4 minutes. Moreover, the average duration of a single outage event is 17.5 minutes

Table 6-3: [redacted] circuit outage characteristics

Year	Number of events	Total number of customer interruptions	Sum of all customer interruption durations (mins)	Customer average interruption duration (mins)
2017	2	3505	40,014	11.4
2016	13	444	67,301	151.6
2015	7	146	10,770	73.8
2014	12	1775	217,020	122.3
2013	8	85	10,193	119.9
2012	16	3444	536,432	155.8
2011	10	333	32,539	97.7
2010	2	2	107	53.5
2009	6	440	109,579	249.0
2009	7	1972	100,033	50.7
2007	3	8	1,026	128.3
2006	10	2035	952,832	468.2
Average Annual	8.3	1234	180,682	146.4

Table 6-4 shows the inception time and duration of the six transmission system outages that occurred in the past 11.5 years. The maximum recorded duration of a transmission system outage is 117 minutes, or approximately 2 hours.

Table 6-4: Inception time and duration of transmission outages

Outage Inception Timestamp	Outage Duration (mins)
Mar 03, 16:42	10
Feb 06, 17:13	13
Jul 13, 12:48	2
Apr 28, 16:33	117
Dec 16, 19:27	63
Aug 16, 14:40	111

6.1.2.4 Energy Storage System sizing

In this use case the following ESS sizes have been evaluated:

- 2 MW 2-hour system (approximately 4 MWh)
- 4 MW 1.5-hour system (approximately 6 MWh)

The reasons for the selecting the 2 MW 2-hour system are as follows:

- Assumed coincident peak demand of [redacted] load cluster is [redacted]. A 2 MW ESS can supply peak load if these facilities are islanded.
- Assumed coincident peak demand of [redacted] loads is [redacted]. The 2 MW ESS can supply peak demand during a critical period, for example if there is a transmission system outage during an event at the [redacted].
- The maximum duration of any transmission system outage over the past 11.5 years is 117 minutes. A 2 MW 2 hour ESS will be able to provide islanded backup for the [redacted] loads in the event of transmission system outage under peak load conditions.

The reasons for evaluating a larger size 4 MW 1.5-hour system are as follows:

- 4 MW power capacity potentially doubles the frequency response capacity that can be contracted with the system.
- 6 MWh energy capacity can supply peak [redacted] loads under islanded condition over 3.5 to 4 hours.

6.1.2.5 Evaluation of islanded reliability

We evaluate customer reliability under distribution and transmission outage scenarios by simulating minute by minute operation of ESS under islanded conditions for each of the 96 recorded outages. At the inception of the outage, the state of charge of the storage device is assumed to be 100%. Islanded load during the outage is derived from the hourly load profiles of the customer facilities. The islanded load served is modeled through a continuous function under the assumption that there exists sufficient measurement fidelity and fast switching to enable appropriate load shedding that balances load and generation at each time interval. This assumption ignores the impact of distribution system topology, load shedding and restoration schedules and switchgear controls. Instead, the assumption allows the use case to focus on the capability of installed devices to meet customer load during outage conditions.

The ESS may be integrated with customer installed PV under islanded conditions. An ESS can monitor solar PV production and customer load to balance generation, load, and state of charge. This configuration allows additional customer loads to be suppled under outages longer than 2 hours, particularly during periods of solar production.

Islanded operation under five outage scenarios is shown in Table 6-5 and Table 6-6. Table 6-5 shows customer load served under an integrated Solar + Storage system, while Table 6-6 depicts customer load served under stand-alone ESS. The outage scenarios are as follows:

- Outage scenario 1: The outage occurs at 12:18 PM and lasts for 164 minutes. Total customer load requirement over the duration is [redacted] with an average load of [redacted] per hour. PV production is low due to cloudy conditions and the storage system supplies most of the load.

- Outage scenario 2: This outage starts at 4:24 PM and lasts over 15 hours. Total customer load over this period is [redacted] at an average of [redacted]. PV production is negligible since the outage period is mostly during the night. The ESS supplies load until it runs out of charge. Overall, 38% of customer load is served.
- Outage scenario 3: The outage starts at 9:00 AM and lasts over 6 hours. PV production is high during this period. Combined PV and storage supplies 90% of the load.
- Outage scenarios 4 and 5: Both outages are of duration less than an hour. 100% of customer load under outage is served.

Table 6-5: Customer load served during PV + Storage islanding under 5 example outages

Outage #	Outage Inception	Duration (min)	Customer Load (kWh)	PV Production (kWh)	PV to Load (kWh)	PV to Storage Charging (kWh)	Storage to Load (kWh)	Load Served (kWh)	% Load Served
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

As shown in Table 6-6, there is a substantial difference in customer load served under outage scenario 3 between solar + storage and stand-alone storage systems. Without solar PV, the battery supplies load until it runs out of energy. In this scenario, 61% of customer load under outage is served.

Table 6-6: Customer load served during stand-alone Storage islanding under 5 example outages

Outage #	Outage Inception	Duration (min)	Customer Load (kWh)	Storage to Load (kWh)	Load Served (kWh)	% Load Served
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 6-7 shows the results of evaluating 87 distribution system outages and 6 transmission system outages. It is assumed that under transmission system outage, the microgrid will prioritize serving [redacted] loads. Customer load in [redacted] will not be served. A 2 MW 2 hour stand-alone ESS can supply on an average [redacted] of customer load under outage. A 4 MW 1.5-hour ESS can supply [redacted] customer load under outage at an average. Integrating the ESS with customer sited Solar PV under islanded conditions results in the possibility of supplying an additional [redacted] of customer load. 100% of [redacted] loads can be supplied under both storage sizing scenarios for all outage cases examined.

Table 6-7: Reliability evaluation results

	Distribution outages, Solar + Storage	Distribution outages, only storage	Transmission outages, Solar + Storage	Transmission outages, only storage
Average customer load served under outage by 2 MW 2 hour system	[redacted]	[redacted]	[redacted]	[redacted]
Average customer load served under outage by 4 MW 1.5 hour system	[redacted]	[redacted]	[redacted]	[redacted]

6.1.2.6 Benefit of mitigating customer interruptions

Reliability benefits to specific customers may not accrue as a tangible benefit to a storage project. However, the 'soft value' of this benefit may be assessed for storage cost-effectiveness evaluation. The U.S. Department of Energy funded a report by Lawrence Berkeley National Labs (LBNL) to derive average and specific values of power disruptions for different customer classes in various regions in the U.S. Table 6-8 shows the estimated interruption cost per outage event, average kW, and unserved kWh by duration and customer class.

From Table 6-8, the interruption cost of medium and large commercial and industrial (C&I) customers varies from $96.5 to $10.6 per kWh from momentary interruptions to 8 hour outages. The average duration of an outage event on [redacted] is 18 minutes. Through linear interpolation, the cost of customer interruption for an 18-minute outage is $58.1 in US 2008$. Escalating the value of US $ by 2.5% annually, the equivalent cost is $74.3 in US 2018$.

Table 6-8: Estimated average electric customer interruption costs US 2008$, anytime by duration and customer type [12]

Interruption Cost	Interruption Duration				
	Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I					
Cost Per Event	$6,558	$9,217	$12,487	$42,506	$69,284
Cost Per Average kW	$8.0	$11.3	$15.3	$52.1	$85.0
Cost Per Un-served kWh	$96.5	$22.6	$15.3	$13.0	$10.6
Cost Per Annual kWh	9.18E-04	1.29E-03	1.75E-03	5.95E-03	9.70E-03
Small C&I					
Cost Per Event	$293	$435	$619	$2,623	$5,195
Cost Per Average kW	$133.7	$198.1	$282.0	$1,195.8	$2,368.6
Cost Per Un-served kWh	$1,604.1	$396.3	$282.0	$298.9	$296.1
Cost Per Annual kWh	1.53E-02	2.26E-02	3.22E-02	$0.137	$0.270
Residential					
Cost Per Event	$2.1	$2.7	$3.3	$7.4	$10.6
Cost Per Average kW	$1.4	$1.8	$2.2	$4.9	$6.9
Cost Per Un-served kWh	$16.8	$3.5	$2.2	$1.2	$0.9
Cost Per Annual kWh	1.60E-04	2.01E-04	2.46E-04	5.58E-04	7.92E-04

The value of customer average interruption duration on the [redacted] circuit is 146.4 minutes per year. For the 93 outages simulated, the average customer load under outage over is [redacted] per hour. Hence the average customer load interrupted annually is [redacted]. Table 6-9 derives the annual value of microgrid reliability for mitigating distribution system outages on [redacted]. The range of annual benefits is from [redacted]. Integrating the ESS with customer sited Solar PV increases benefits by [redacted] over stand-alone ESS.

Table 6-9: Customer reliability benefit results

	Solar + Storage	Stand-alone ESS
Customer average interruption duration	[redacted]	[redacted]
Average customer load under outage per hour	[redacted]	[redacted]
Average customer load interrupted annually	[redacted]	[redacted]
Customer load under interruption served by microgrid with 2 MW 2 hr ESS (%)	[redacted]	[redacted]
Customer load under interruption served by microgrid with 4 MW 1.5 hr ESS (%)	[redacted]	[redacted]
Customer load under interruption served by microgrid with 2 MW 2 hr ESS (kWh annual)	[redacted]	[redacted]
Customer load under interruption served by microgrid with 4 MW 1.5 hr ESS (kWh annual)	[redacted]	[redacted]
Value of customer reliability ($) @ $74.3 per kWh of interrupted load served with 2 MW 2 hour ESS	[redacted]	[redacted]
Value of customer reliability ($) @ $74.3 per kWh of interrupted load served with 4 MW 1.5 hour ESS	[redacted]	[redacted]

It is to be noted that the benefits in Table 6-9 are estimated only for mitigating distribution system outages on the [redacted] circuit. Transmission outages are extremely rare and using this methodology, the benefit estimate of supporting stadium loads during a transmission outage would be negligible. However, even though the statistical probability is low, the actual cost of a transmission outage causing loss of load at the [redacted] particularly during [redacted] would be extremely high. Neglecting this benefit provides a conservative estimate of cost-effectiveness of energy storage systems for microgrid reliability.

6.1.2.7 Stacked application evaluation

In providing microgrid reliability, the ESS discharges at an average of 8 times a year for a total discharge time of 146 minutes. Due to very low usage requirements, this application can be stacked or combined with the following additional applications

- Primary frequency response – The power capacity of the ESS can be contracted to provide primary frequency response. Per the frequency response application methodology detailed in Section 4.1.2, on receiving a frequency response trigger, the ESS will respond as follows:
    - Zero to full power within 10 seconds.
    - Discharge at full power for 360 seconds.
    - Ramp down to zero power from full power within 120 seconds.

Assuming an ESS with 82% round-trip frequency, for a frequency response contract of 2 MW, the total energy discharged during this performance cycle is 260 kWh. If the contracted capacity is 4 MW, the total energy discharged is 520 kWh.

When stacking frequency response with distribution transformer upgrade deferral, there is non-zero probability that a frequency event will occur after the ESS has discharged full capacity to reduce circuit load and has not had the opportunity to recharge sufficiently. Hence, for this stacked application, system energy capacity needs to be reserved for frequency response.

- [redacted] substation upgrade deferral – The ESS can discharge during circuit peak load day to defer substation transformer upgrade required to mitigate circuit overload conditions. A power flow analysis of the [redacted] circuit demonstrates that there is negligible difference in power requirement for deferral if the ESS is interconnected at the end of circuit instead of the substation. Reserving energy capacity for frequency response, the available capacity for upgrade deferral is as follows:
    - For a 2 MW 2 hr ESS, 300 kWh is reserved for frequency response and 3.7 MWh is available for upgrade deferral.
    - For a 4 MW 1.5 hr ESS, 550 kWh is reserved for frequency response and 5.45 MWh is available for upgrade deferral.

Evaluating upgrade deferral by the methodology detailed in section 5.3.3 a 2 MW 3.7 MWh ESS can defer $3,000,000 transformer upgrade over a four-year period from 2021 to 2024. A 4 MW 5.45 MWh ESS can defer the transformer upgrade over a 6 year period from 2021 to 2026.

We evaluate benefits of deferral per the methodology described in Section 5.3.2. The benefits of four year substation transformer deferral with 2 MW 3.7 MWh ESS is shown in Table 6-10, and six year substation transformer deferral with 4 MW 4.45 MWh ESS is shown in Table 6-11.

Table 6-10: Benefits of four year substation transformer deferral with 2 MW 3.7 MWh ESS

	2021	2022	2023	2024	2025
Deferral benefit - equity	$1,543,200	$0	$0	$0	$(1,543,200)
Deferral benefit - debt	$83,026	$83,026	$83,026	$83,026	$0
Avoided transformer O&M cost	$8,500	$8,500	$8,500	$8,500	$0

Table 6-11: Benefits of six year substation transformer deferral with 4 MW 5.45 MWh ESS

	2021	2022	2023	2024	2025	2026	2027
Deferral benefit - equity	$1,543,200	$0	$0	$0	$0	$0	$(1,543,200)
Deferral benefit - debt	$83,026	$83,026	$83,026	$83,026	$83,026	$83,026	$0
Avoided transformer O&M cost	$8,500	$8,500	$8,500	$8,500	$8,500	$8,500	$0

Note that the upgrade deferral and primary frequency response applications can be combined with microgrid reliability in a non-intrusive manner. In the event of outages, the ESS would be disconnected from the electric grid and will provide islanded reliability. Under parallel operation, the ESS may perform circuit load reduction or primary frequency response.

6.1.3 Assumptions and methodology limitations

The following assumptions are embedded within our methodology for evaluating microgrid reliability and stacked application benefits of ESS:

- Customer load profiles were derived by simulating the energy consumption of statistically benchmarked buildings equivalent to ASHRAE 90.1 2013 – code efficiencies and requirements and calibrating the hourly profiles to monthly meter data. The simulated building types are assumed to approximate the behavior of evaluated buildings. Accuracy of benefit evaluation can be improved by using actual interval metered load measurements.
- Outage analysis was performed at a circuit level. We assume that since the customers under evaluation are at the end of the [redacted] circuit, all circuit outages will affect this customer. The analysis can be improved by using logged outage data recorded at evaluated customer sites.
- Benefits of serving interrupted customer load are based on a national average of C&I customers. This benefit is heavily dependent on building population, activity and services interrupted by outage. Outage mitigation benefits for specific customers can be determined by conducting a survey of the facility, energy consumption, scheduled activities and their estimated monetary value as determined by the customer. We believe the outage benefit values used in this analysis is conservative
- The islanded load served is modeled through a continuous function under the assumption that there exists sufficient measurement fidelity and fast switching to enable appropriate load shedding that balances load and generation at each time interval. This assumption ignores the impact of load categorization, load shedding and restoration schedules and switchgear controls that will be implemented in an actual deployed system.
- Microgrid reliability benefits are evaluated only considering distribution outage on the [redacted] circuit. The value of reliability provided to stadium loads under transmission outage has been neglected due to the low frequency of transmission outages. This assumption is extremely conservative. The cost of an outage on the [redacted] during a highly visible event can be very high and may be estimated by reviewing the contract value of scheduled events.

6.1.4 Modeling results

Cash flow analysis is performed over 20-year project life using cost and financial assumptions detailed in Error! Reference source not found.. Cost-effectiveness results in terms of NPV, IRR, and BCR is shown in Table 6-12. Results for all combinations of the following scenarios are presented:

- ESS size 2 MW 2 hr and 4 MW 1.5 hr
- Microgrid reliability with stand-alone ESS and integration with customer sited Solar PV
- Upgrade deferral of 4 years achieved with 2 MW 2 hr ESS and 6 years with 4 MW 1.5 hr ESS
- Frequency response at contract value of $44.4/kW-year and $81/kW-year

High level conclusions that can be drawn from the results are:

- A high number of scenarios are cost-effective. Of the 24 scenarios evaluated, 9 are cost effective with a BCR greater than 1.
- A further 3 scenarios are marginally cost effective with BCR greater than 0.9 and less than 1.
- Microgrid reliability and upgrade deferral applications are not cost-effective individually. Combined with frequency response at contracted value of $81/kW-year, these applications are cost-effective.
- 2 MW 2 hour ESS performing microgrid reliability with customer PV integration, 4 year upgrade deferral and frequency response at a contract value of $44.4/kW-year may be considered the break-even scenario.
- In general, the 2 MW 2 hour system is marginally more cost-effective than the 4 MW 1.5 hour system. However, the larger sized system can provide higher reliability to customer loads, particularly [redacted] loads. Additionally, the 4 MW system can contract higher capacity for frequency response.

Table 6-12: Cost effectiveness results for microgrid reliability and stacked applications

ESS Size	Project Cost	Reliability integration scenario	Upgrade deferral scenario	FR scenario	NPV	IRR	BCR
2 MW 4 MWh	$2,362,000	Stand-alone ESS	N/A	N/A	($1,915,052)	-11.6%	0.34
2 MW 4 MWh	$2,362,000	Integration with customer sited PV	N/A	N/A	($1,819,787)	-10.1%	0.37
2 MW 4 MWh	$2,362,000	Stand-alone ESS	4 year	N/A	($1,352,540)	-13.6%	0.53
2 MW 4 MWh	$2,362,000	Integration with customer sited PV	4 year	N/A	($1,257,274)	-11.6%	0.56
2 MW 4 MWh	$2,362,000	Stand-alone ESS	N/A	$44.4/kW-yr	($658,991)	1.7%	0.77
2 MW 4 MWh	$2,362,000	Integration with customer sited PV	N/A	$44.4/kW-yr	($563,726)	2.5%	0.80
2 MW 4 MWh	$2,362,000	Stand-alone ESS	4 year	$44.4/kW-yr	($96,479)	5.4%	0.97
2 MW 4 MWh	$2,362,000	Integration with customer sited PV	4 year	$44.4/kW-yr	($1,213)	6.6%	1.00
2 MW 4 MWh	$2,362,000	Stand-alone ESS	N/A	$81/kW-yr	$376,410	9.2%	1.13

ESS Size	Project Cost	Reliability integration scenario	Upgrade deferral scenario	FR scenario	NPV	IRR	BCR
2 MW 4 MWh	$2,362,000	Integration with customer sited PV	N/A	$81/kW-yr	$471,676	9.9%	1.16
2 MW 4 MWh	$2,362,000	Stand-alone ESS	4 year	$81/kW-yr	$938,923	17.8%	1.33
2 MW 4 MWh	$2,362,000	Integration with customer sited PV	4 year	$81/kW-yr	$1,034,188	18.9%	1.36
4 MW 6 MWh	$4,014,000	Stand-alone ESS	N/A	N/A	($3,760,527)	N/A	0.23
4 MW 6 MWh	$4,014,000	Integration with customer sited PV	N/A	N/A	($3,689,181)	-17.5%	0.24
4 MW 6 MWh	$4,014,000	Stand-alone ESS	6 year	N/A	($2,966,238)	N/A	0.39
4 MW 6 MWh	$4,014,000	Integration with customer sited PV	6 yr	N/A	($2,894,892)	N/A	0.41
4 MW 6 MWh	$4,014,000	Stand-alone ESS	N/A	$44.4/kW-yr	($1,248,406)	1.1%	0.74
4 MW 6 MWh	$4,014,000	Integration with customer sited PV	N/A	$44.4/kW-yr	($1,177,059)	1.5%	0.76
4 MW 6 MWh	$4,014,000	Stand-alone ESS	6 year	$44.4/kW-yr	($454,116)	3.7%	0.91
4 MW 6 MWh	$4,014,000	Integration with customer sited PV	6 year	$44.4/kW-yr	($382,770)	4.2%	0.92
4 MW 6 MWh	$4,014,000	Stand-alone ESS	N/A	$81/kW-yr	$822,398	10.0%	1.17
4 MW 6 MWh	$4,014,000	Integration with customer sited PV	N/A	$81/kW-yr	$893,744	10.2%	1.18
4 MW 6 MWh	$4,014,000	Stand-alone ESS	6 year	$81/kW-yr	$1,616,687	16.1%	1.33
4 MW 6 MWh	$4,014,000	Integration with customer sited PV	6 year	$81/kW-yr	$1,688,033	16.5%	1.35

Table 6-13 and Table 6-14 (following page) shows the 20-year cash flow for 2 MW 2 hr ESS performing microgrid reliability with solar and storage integration, primary frequency response at contract value of $81/kW-year in the first year and substation transformer upgrade deferral for four years.

Table 6-13: 20-year cash-flow for 2 MW 2 hour ESS performing microgrid reliability with solar + storage integration, primary frequency response at contract value of $81/kW-year and substation transformer deferral **($ ‘000s)**

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Reliability benefit	$75.1	$77.0	$78.9	$80.9	$82.9	$85.0	$87.1	$89.3	$91.5	$93.8
Frequency response benefit	$162.0	$166.1	$170.2	$174.5	$178.8	$183.3	$187.9	$192.6	$197.4	$202.3
Upgrade deferral benefit	$0.0	$0.0	$0.0	$1,634.7	$91.5	$91.5	$91.5	($1,543.2)	$0.0	$0.0
Total savings / revenue	$237.1	$243.0	$249.1	$1,890.1	$353.3	$359.8	$366.5	($1,261.3)	$288.9	$296.1
Fixed O&M cost	($12.0)	($12.3)	($12.6)	($12.9)	($13.2)	($13.6)	($13.9)	($14.3)	($14.6)	($15.0)
Capacity maintenance cost	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)
Equity draw	($1,215.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Interest payment	($60.3)	($55.6)	($50.6)	($45.4)	($39.8)	($34.0)	($27.9)	($21.4)	($14.7)	($7.5)
Principal payment	($90.1)	($94.8)	($99.8)	($105.1)	($110.6)	($116.4)	($122.5)	($129.0)	($135.8)	($142.9)
Total debt payment	($150.4)	($150.4)	($150.4)	($150.4)	($150.4)	($150.4)	($150.4)	($150.4)	($150.4)	($150.4)
Total savings / revenue	$237.1	$243.0	$249.1	$1,890.1	$353.3	$359.8	$366.5	($1,261.3)	$288.9	$296.1
Total costs	($1,407.4)	($192.7)	($193.0)	($193.3)	($193.7)	($194.0)	($194.3)	($194.7)	($195.0)	($195.4)
Annual cash flow	($1,170.3)	$50.3	$56.1	$1,696.7	$159.6	$165.8	$172.2	($1,456.0)	$93.9	$100.7

Table 6-14: (continued) 20-year cash-flow for ESS performing microgrid reliability with solar + storage integration, primary frequency response at contract value of $81/kW-year and substation transformer **deferral ($ '000s)**

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Reliability benefit	$96.2	$98.6	$101.0	$103.6	$106.1	$108.8	$111.5	$114.3	$117.2	$120.1
Frequency response benefit	$207.4	$212.6	$217.9	$223.3	$228.9	$234.6	$240.5	$246.5	$252.7	$259.0
Upgrade deferral benefit	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total savings / revenue	$303.5	$311.1	$318.9	$326.9	$335.0	$343.4	$352.0	$360.8	$369.8	$379.1
Fixed O&M cost	($15.4)	($15.7)	($16.1)	($16.5)	($17.0)	($17.4)	($17.8)	($18.3)	($18.7)	($19.2)
Capacity maintenance cost	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)	($30.0)
Equity draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Interest payment	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Principal payment	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total debt payment	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total savings / revenue	$303.5	$311.1	$318.9	$326.9	$335.0	$343.4	$352.0	$360.8	$369.8	$379.1
Total costs	($45.4)	($45.7)	($46.1)	($46.5)	($47.0)	($47.4)	($47.8)	($48.3)	($48.7)	($49.2)
Annual cash flow	$258.2	$265.4	$272.8	$280.3	$288.1	$296.0	$304.2	$312.5	$321.1	$329.9

6.2 Distribution Upgrade Deferral with Distributed Storage

6.2.1 Inputs required

The inputs required for this methodology are as described in Section 5.3.

6.2.2 Methodology description and assumptions

The methodology required is as described in Section 5.3. The methodology and results presented for distribution upgrade deferral in Section 5.3 consider centralized energy storage system at the substation. Determining the optimal sizing and location of distributed storage along the feeder is beyond the scope of this project. However, assuming that the same amount of peak reduction can be provided by distributed storage, a financial evaluation can be performed to estimate the cost effectiveness of distributed storage and compare it against centralized storage.

For this application, we consider a use case where PacifiCorp procures capacity for upgrade deferral from an aggregator. The aggregator is responsible for the integration and operation on energy storage systems, and must ensure that the procured capacity is provided to PacifiCorp when needed.

6.2.3 Results

The results from 5.3.3 were used to estimate the capacity needed for deferral. Further, the number of years of deferral and total deferral benefit were used to estimate the capacity price which makes this application cost-effective for PacifiCorp. Capacity rate (in $/kW-month) is the monthly payment per kW capacity which PacifiCorp pays an aggregator to provide the capacity needed for peak reduction. The monthly capacity rate can be extended out to an annual rate by multiplying the rate by 12.

Table 6-15 shows the capacity requirements and capacity rates at the break-even point for [redacted] substation. Any values above the rates shown in Table 6-15, makes the use case financially nonviable, based on the transformer upgrade costs cited by PacifiCorp.

Table 6-15: Capacity Requirement and Rates for Distributed Energy Storage Use Case on Hillview

Substation	Scenario #	ES Power Rating (MW)	ES Energy Capacity (MWh)	Years of Deferral	Capacity Requirement (MW)	Capacity Rate ($/kW-month)	Capacity Rate ($/kW-year)
Hillview	Scenario 1	1	2	2	1.00	$15.10	$181.16
	Scenario 3	2	4	4	2.00	$7.10	$85.15
	Scenario 5	4	8	7	3.41	$3.80	$45.64
	Scenario 6	4	16	8	4.00	$3.15	$37.78
	Scenario 7	6	12	9	4.48	$2.73	$32.77
	Scenario 8	6	24	10	6.00	$1.13	$13.62

Typically, DNV GL has observed capacity rates in the current market to be approximately twice the rates calculated here for Scenario 1. As such, this case is likely not viable on its own, as was previously noted in the use case for a centralized system. However, located at a customer-site behind the meter, these systems could additionally provide reliability, peak shaving, load shifting, and renewables integration support to the customer. These stacked benefits could provide a viable case for this application. Additionally, if transformer upgrade costs are found to be greater than cited, the economic calculations can be updated to reflect this and provide more favorable BCR.

6.3 Voltage Support with Distributed Storage

6.3.1 Inputs required

The inputs required for this methodology are as described in Section 5.1.

6.3.2 Methodology description and assumptions

The methodology required is as described in Section 5.1.

6.3.3 Results

As previously described in Section 5.1, Figure 5-3 showed the branches of the feeder that experience voltage violations. Provided that the ESS is of the required size, it can be sited anywhere on these branches, or distributed around several customers on these branches. As noted for the other customer sited cases, more distribution of energy storage systems could provide additional benefits, such as improving customer reliability, supporting customer savings through peak shaving or load shifting, and facilitating integration of on-site renewables, such as residential scale solar PV. Since the economics for the 17 kVA ESS case are positive, stacking these applications would provide an even more desirable BCR. The 35 kVA case, while calculated at a lower BCR for the centralized solution, stacked with other applications and distributed over multiple customers, who could broaden the scope not only of economic benefit, but customer satisfaction.

7 MODELING RESULTS ASSESSMENT

PacifiCorp has developed this document and the process and results described herein to comply with 2015 HB 2193, the subsequent Order 16-504 UM 1751, and the final guidelines from the OPUC relating to these items. As described in the previous sections, PacifiCorp considered multiple use cases, and applications to benefit the transmission system, distribution system, and customer were analyzed based on 6 representative feeders, other publicly available data, and assumed market conditions. A high level consolidation of the results of these studies are summarized in Table 7-1.

Table 7-1 Summary of modeling results

Use Case	Energy Storage System Size	Economic considerations		
Frequency response	10 MW / 2 MWh	FR rate @ $44.40, BCR = 0.97 FR rate @ $81, BCR = 1.78		
Congestion	None recommended	N/A		
Volt/VAR	(1) 35 kVA / 4 hr (2) 17 kVA / 4 hr	(1) Low: BCR = 0.23 Average: BCR = 0.30 High: BCR = 0.76 (2) Low: BCR = 0.47 Average: BCR = 0.625 High: BCR = 1.56		
Reliability	None recommended	N/A		
Distribution upgrade deferral	Hillview	Deferral yrs	BCR w/ Deferral	BCR w/ Stacked
	(1) 1 MW / 2 MWh	2	0.36	0.81
	(2) 1 MW / 4 MWh	2	0.23	0.53
	(3) 2 MW / 4 MWh	4	0.34	0.66
	(4) 2 MW / 8 MWh	4	0.22	0.43
	(5) 4 MW / 8 MWh	7	0.27	0.41
	(6) 4 MW / 16 MWh	8	0.20	0.26
	(7) 6 MW / 12 MWh	9	0.22	0.26
	(8) 6 MW / 24 MWh	10	0.15	0.15
	(9) 8 MW / 8 MWh	7	0.18	0.38

Use Case	Energy Storage System Size	Economic considerations			
	Independence	-	-	-	
	(1) 6 MW / 24 MWh	1	0.02	N/A	
	(2) 10 MW / 20 MWh	1	0.01		
	(3) 10 MW / 60 MWh	2	0.01		
	Lyons	-	-	-	
	(1) 6 MW / 36 MWh	1	0.01	N/A	
	(2) 8 MW / 32 MWh	1	0.02		
	(3) 8 MW / 48 MWh	2	0.02		
	(4) 10 MW / 60 MWh	3	0.03		
Customer Sited, Utility Owned with Stacked Applications	(1) 2 MW / 4 MWh	(1) System	(1) Deferral	(1) FR	(1) BCR
		ESS	N/A	N/A	0.34
		Solar + ESS	N/A	N/A	0.37
		ESS	4 year	N/A	0.53
		Solar + ESS	4 year	N/A	0.56
		ESS	N/A	$44.40	0.77
		Solar + ESS	N/A	$44.40	0.80
		ESS	4 year	$44.40	0.97
		Solar + ESS	4 year	$44.40	1.00
		ESS	N/A	$81	1.13
		Solar + ESS	N/A	$81	1.16
		ESS	4 year	$81	1.33
		Solar + ESS	4 year	$81	1.36
	(2) 4 MW / 6 MWh	(2) System	(2) Deferral	(2) FR	(2) BCR
		ESS	N/A	N/A	0.23
		Solar + ESS	N/A	N/A	0.24
		ESS	6 year	N/A	0.39
		Solar + ESS	6 year	N/A	0.41
		ESS	N/A	$44.40	0.74

Use Case	Energy Storage System Size	Economic considerations			
		Solar + ESS	N/A	$44.40	0.76
		ESS	6 year	$44.40	0.91
		Solar + ESS	6 year	$44.40	0.92
		ESS	N/A	$81	1.17
		Solar + ESS	N/A	$81	1.18
		ESS	6 year	$81	1.33
		Solar + ESS	6 year	$81	1.35

As previously noted, for these results, the systems were assumed to be generic Lithium Ion systems of the noted size. This assumption reduced variables in the modeling. Additionally, Lithium Ion's current dominance in the energy storage industry provides it with some of the better economics of potential systems, while the technology's flexibility to perform both short and longer duration applications make it practical to assume in the case of stacked applications. It additionally has some of the highest energy density of mature technologies currently on the market. Other technologies should, however, be considered. As such, following are brief overviews of other relatively mature technologies and their appropriateness for these applications, utilizing industry knowledge, the Battery Energy Storage Study [1], DNV GL's Gridstor [3], and Lazard's Levelized Cost of Storage [10].

Flow batteries store electrolyte in tanks. As such, they do not experience the degradation that affects Lithium Ion batteries, their capacity can be increased at relatively low cost with the addition of electrolyte, and they can remain stored for long periods of time without concern for damage. Additionally, they are especially suited to serve long duration storage needs. This technology, however, is higher in cost and less mature, so less field data is available to validate manufacturer claims. Additionally, they have larger footprints than Lithium Ion systems, and thus are only suitable for large commercial, industrial, or utility installations, not distributed smaller systems.

Thermal energy storage is a broad term for a variety of energy storage devices. It covers a wide range of different technologies, wherein a medium is heated or cooled, and that energy is used at a later time. The energy to heat of cool the medium can come from the grid during off-peak times, renewable production that exceeds demand, waste heat, or other sources. This technology is very low cost and, depending on the type of technology, can have a reasonably minimal footprint. Thermal energy storage's largest limiting factor is the speed of response, which can take from seconds to minutes.

Hydroelectric energy has been connected to the grid for decades, and pumped hydro energy storage systems leverage this technological experience. Pumped hydro does not have the chemical degradation concerns which batteries face, but the addition of key moving components provides a different risk. The systems are capable of very high capacity storage, but have large footprints and physical constraints relating to the water source.

While these technologies are either leading in the industry or of particular interest to PacifiCorp, further research will continue to assess other options. Technologies open to consideration span from mechanical (such as flywheels, which are especially suited for fast response, high power applications) to other emerging battery technologies (such as Zinc-air) and further. PacifiCorp is utilizing the contents of this report to support the development of one or many ESS projects which will both meet the guidelines and requirements of the State and the OPUC, and also best serve its customers and stakeholders, ensuring the delivery of safe, reliable, low-cost energy.

8 REFERENCES

[1] PacifiCorp, DNV GL. *Battery Energy Storage Study for the 2017 IRP.* http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/10018304_R-01-D_PacifiCorp_Battery_Energy_Storage_Study.pdf, 2017.

[2] Sandia National Laboratories. *DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA.* http://www.sandia.gov/ess/publications/SAND2015-1002.pdf, 2015.

[3] DNV GL. *Gridstor Recommended Practice: Safety, operation and performance of grid-connected energy storage systems.* http://rules.dnvgl.com/docs/pdf/DNVGL/RP/2015-12/DNVGL-RP-0043.pdf, 2015.

[4] NERC. *Frequency Response Obligation Allocation for Operation Year 2017.* http://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Related%20Files/BA%20FRO%20Allocation%20for%20OY%202017.pdf, 2017.

[5] Scott Benner, Performance, Mileage and the Mileage Ratio, Nov. 11, 2015.

[6] Jeff St.John, Greentech Media, *PJM's Frequency Regulation Market and the Changing Nature of Energy Storage*, Jan 14, 2016

[7] CAISO. *Filing of Rate Schedule No. 85.* http://www.caiso.com/Documents/Nov22_2016_TransferredFrequencyResponseServiceAgreement_BonnevillePowerAdministration_ER17-408.pdf, 2016.

[8] CAISO. *Filing of Rate Schedule No. 85.* http://www.caiso.com/Documents/Nov22_2016_TransferredFrequencyResponseServiceAgreement_City_Seattle_ER17-411.pdf, 2016.

[9] CAISO. *Open Access Same-time Information System.* oasis.caiso.com, 2017.

[10] Lazard. *Lazard's Levelized Cost of Storage – Version 2.0*. https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf, 2016.

[11] California Energy Commission, DNV KEMA, *Energy Storage Cost-effectiveness Methodology and Results*, August 2013.

[12] Ernest Orlando Lawrence Berkeley National Laboratory. *Estimated Value of Service Reliability for Electric Utility Customers in the United States.* https://emp.lbl.gov/sites/all/files/lbnl-2132e.pdf, 2009.

ABOUT DNV GL

Driven by our purpose of safeguarding life, property and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification and technical assurance along with software and independent expert advisory services to the maritime, oil and gas, and energy industries. We also provide certification services to customers across a wide range of industries. Operating in more than 100 countries, our 16,000 professionals are dedicated to helping our customers make the world safer, smarter and greener.